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EVALUATING TREATMENT PARAMETERS TOWARD OPTIMIZING PRODUCTION FROM GAS RESERVOIRS USING WETTABILITY ALTERATION

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EVALUATING TREATMENT PARAMETERS TOWARD OPTIMIZING PRODUCTION FROM GAS RESERVOIRS USING WETTABILITY ALTERATION

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Abstract

Retrograde condensation in gas reservoirs results in a significant loss in well deliverability. A ring of condensate forms near the wellbore as a result of reservoir pressure falling below the dew point of the reservoir gas. Methods commonly used in the industry to alleviate this problem are temporary in nature, but the viability of permanent wettability alteration in the near-wellbore region has been steadily improving in recent years. Past studies in the use of wettability alteration to tackle the problem of retrograde condensation in a gas-condensate reservoir system have had three main focuses; experimental studies to develop chemical modifiers that will effectively adsorb onto the surface of the rock and alter the wettability of the pore walls, studies to ascertain the most effective wettability treatment in gas condensate reservoirs, and analysis of field application of wettability alteration treatments. There are only four known field applications, where two succeeded and two failed, although laboratory trials were encouraging.

In an attempt to understand factors that influence the performance of wettability alteration, a simulation model was developed that consist of combinations of radial reservoirs of various drainage radii, permeabilities, and containing one of three reservoir fluid types characterized by their condensate yields. We investigated the influence of various factors such as fluid types, reservoir permeability, reservoir size, and treatment radius, on the performance of different wettability treatments. Analysis of variance was carried out to ascertain the extent of statistical significance for the differential effect of various reservoir factors influencing the success of treatment.

We discovered that the success of wettability alteration is dependent upon the yield of the reservoir gas. A lean fluid is the least favorable to wettability alteration while a rich fluid is the most

favorable. A low permeability reservoir would benefit more from wettability alteration treatment when compared to a high permeability reservoir. However, the larger the drainage area of a reservoir, the more improved production is achieved from a wettability alteration. In addition, a treatment resulting in a state of neutral wetting appeared to be the most effective treatment for a gas reservoir regardless of the condensate yield of the reservoir gas. In addition, we found out that while the main effect of certain factors appeared insignificant, their interaction with other factors is very significant. Small reservoirs seem to have better post-treatment recovery factors than large reservoirs.

The outcome of this integrated study is expected to serve as a footprint for the field application of wettability alteration treatment to alleviate the problem of condensate blockage in a gas reservoir.

Chapter 1: Introduction

1.1 Problem Statement

A sudden drop in well deliverability is commonly experienced in gas condensate reservoirs due to an accumulation of condensate near the wellbore region at high saturation when the reservoir pressure falls below the dew point pressure of the reservoir gas. The accumulation of liquid at the near-wellbore region is referred to as condensate banking and it compromises the flow assurance of such well. The presence of this condensate bank otherwise known as liquid blockage hampers the production from such a well due to the emergence of two-phase flow and lower relative permeability of gas. Other factors that contribute to the extent of damage to production from such wells include drawdown, fluid composition, etc.

The impact of condensate blocking could be severe and remediation efforts can be very expensive. As a result, standard practices focus on prevention through chemical injection or pressure management. There are two underlying principles of methods used to improve gas production after a decline due to condensate banking. Removal of condensate by lowering the capillary pressure or increasing the drawdown pressure. The guiding relationship for the capillary pressure is the Young-Laplace equation which establishes that the capillary pressure (P_c) is directly proportional to the contact angle (θ), interfacial tension (σ) but inversely proportional to the pore size (r_p).

$$P_c = \frac{2\sigma cos\theta}{r_p}$$

Several methods such as solvent injection, gas injection, hydraulic fracturing, etc. have been used to alleviate the effect of condensate banking. However, these methods have only recorded temporary successes as the condensate accumulation at the near-wellbore returns again.

Reservoir rock is by default liquid-wet; likely water-wet, at times oil-wet or a combination of both. However, rock can be permanently altered to a gas-wetting state through the injection of surface acting chemicals. Precautionary treatment of the near-wellbore region of the reservoir with chemicals such as fluoropolymers can alter the wettability of the affected rock to entirely gas-wetting, or to an intermediate state of liquid and gas-wetting. Altering the wettability within the treatment radius would constitute reducing the liquid saturation in that area without inhibiting the flow of gas. This leads one to assume that the optimal wettability state of the near-wellbore region is a mixture of liquid and gas-wetting, rather than purely gas-wetting. In a strong gas-wetting environment, the reservoir gas cannot displace the trapped liquid if it's being detained by interactions at the mineral face.

1.2 Experimental Studies

Verifying this concept is challenging for various reasons, among them is the variability between the cores of natural reservoirs, typically limestone or sandstone, in terms of porosity, permeability, pore structure, natural fractures, coring method, and rock type. Most of this experimental work focuses on the suitable chemical selection to alter the wettability of the reservoir because the anionic and cationic surfactants used for permanent wettability alteration is made up of a large and diverse body of chemicals whose compatibility vary with rock and fluid types. Li and Firoozabadi (2000) modeled gas and liquid relative permeability curves for retrograde condensate fluids, it was established that increased deliverability could be expected from alteration to strong gas-wetting or intermediate gas-wetting from the default strong liquid-wetting state. The experiment samples rock with permeability ranging from 1 md to over 1000 md before treatment with surface acting chemicals. A permanent wettability alteration was observed, the absolute permeability was reduced as a result of treatment, but not significantly.

The fluoro-polymers used in many of these experiments permanently alter the wettability state of mineral grains by causing an acid-base reaction at the solid-fluid interface that results in permanent adsorption of the chemical to the grain-surface and generating low free surface energy (Fahes and Firoozabadi 2007). Tang and Firoozabadi (2002) present an interesting nuance because it tests two chemicals, one of which is only 5% of the cost of the other. The increase in liquid relative permeability on Berea and chalk samples as a result of wettability alteration was analyzed, with the conclusion that the cheaper chemical was as effective, if not more effective, than the second chemical. Contact-angle measurements, imbibition tests, and unsteady state flow tests are common methods of quantifying the results of these laboratory experiments (Mohammed and Babadagli 2016).

Fahimpour and Jamiolahmady (2015) have determined through experimental means that fluorinated wettability modifiers have had success in achieving an intermediate gas-wetting state in carbonate cores that alleviates condensate banking if proper filtration of the injection chemical is conducted to prevent core plugging. Both ambient and reservoir conditions of temperature and pressure were explored using binary gas/condensate fluids (methane and decane). Understandably, the significant investment required for reservoir-scale wettability modification and the associated risk of formation damage from chemical particulate and EUR reduction makes the prospect of field trials of wettability modifiers quite daunting.

1.3 Simulation studies

Simulation approaches to this problem have also been explored, and present their unique challenges, not the least of which is the perception that simulation-based evidence is not substantial enough to justify field applications. One might also encounter discrepancies between model runs that have varying grid sizes, time step sizes, error tolerances and other numerical properties with no relevance to the real physics of a reservoir. A key difference between experimental approaches to this problem and simulations is that, while experiments are often limited to binary fluids for consistency, simulations can incorporate complex fluid systems with ten or more components. Zoghbi et al. (2010) utilized a radial reservoir model in CMG to compare the effect of an altered wettability zone around the wellbore on ultimate recovery; it is the precursor to the design of the simulation study. The results of this work suggest that both the wholly gas wetting and intermediate gas-wetting states are more advantageous in the mitigation of condensate banking when compared to the control case of an unaltered liquid-wetting reservoir. Furthermore, the intermediate gas-wetting case was shown to have a slightly higher recovery than the strong gas-wetting case for the single gas composition that was used, and for all permeability values that were investigated (1 md, 10 md, and 100 md). The improvement becomes more pronounced as the permeability decreases from 100 md to 1 md. The effects of initial reservoir pressure and treatment radius were also examined. The limitations of this study become apparent when one considers that only a single gas condensate composition was tested.

Delavarmoghaddam et al. (2009) considers two similar fluid compositions (methane fractions of approximately 65% and 68%) and examines the effects of water saturation and permeability (1 md, 10 md, and 50 md) with the conclusion that the benefit of an intermediate gas-wetting state is more pronounced in the leaner of the two-fluid compositions. Still, an economic discussion is lacking, which is the most important factor when discussing industry application in the field. The study goes on to conclude that a strong gas-wetting state could be detrimental to production because the adsorption of the chemical to the rock face inhibits the flow of fluid. This has profound economic ramifications because it suggests that aggressive treatment in a field application would not only be more expensive, but it would result in poorer performance than a moderate treatment.

1.4 Research gaps

Several successes have been accomplished in the laboratory in identifying optimum wettability condition for various core samples. Besides, several fluoro-polymer/surfactants have been modified to ensure thy are effective for wettability alteration at the extreme reservoir condition such as high temperature. As we know, laboratory experiments occur in an ideal set-up and do not always translate to reality. Several field trials have been conducted, but only one case of success was recorded. Also, many simulations studies have been carried out with factors and parameters that do not cover a wide spectrum of properties that could influence the performance of wettability alteration at the field scale. For example, Zoghbi et al. (2010) only consider one fluid type, and one reservoir size, Sakhaei et al (2017) considers one fluid type, one permeability, and one reservoir size. Some conclusions drawn in earlier studies need further verification. Delavarmorghaddam et al (2009) concluded that wettability treatment of lean gas reservoir is more effective than rich gas reservoir even though a rich gas would experience more condensate formation at low pressure. While Ajagbe et al. (2018) established that reservoir gas with higher C7+ components is a better candidate for treatment. In addition, Zoghbi et al (2010) and Sakhaei et al (2017) drew conclusions on various treatment radius without an economic analysis to justify their claims.

1.5 Research objective and chapter summaries

The purpose of this research to investigate the effect of permanent wettability alteration treatment of the near-wellbore region on a long-term reservoir production capacity. This work will be primarily simulation. The simulation would involve reservoirs of three different radii, two permeability, three fluid types, and three wettability states. The objectives of this study are summarized below;

- Establish the optimal wettability alteration treatment for each reservoir types
- Establish the optimal wettability alteration treatment for each fluid types
- Establish the optimal wettability alteration treatment for each permeability value
- Establish the effect of the interaction of various factors on the stimulation performance

Chapter 3 presents the methodology of the research. A detailed description of the reservoir and fluid model is highlighted in this chapter. In addition, the rock fluid interaction, technical, and the approach used to analyze results from the experiments are summarized in the chapter. Results presented in chapter 4 are from simulation analysis with inputs from past experiments with additional factors considered – treatment radius, fluid types, and permeability. The objective is to close the research gaps identified in past studies and verify if the conclusions drawn hold. In chapter 5, we subject our results to statistical analysis to investigate if the conclusions from past studies and our new observations from this simulation are statistically significant to the response variable. We use the 2^k factorial design of analysis of experiment at this stage. The final simulation objective is to identify the impact of well spacing on wettability alteration in a giant gas condensate reservoir. We used nodal analysis to estimate the operational conditions for flow rate and flowing bottom hole pressure across the fluid types and reservoir sizes. The summary of key observations from this study is presented in chapter 7.

Chapter 2: Literature Review

Though the use of wettability alteration to optimize production from gas condensate reservoir is a recent phenomenon, several works have been carried out to investigate the use of wettability alteration to alleviate the effect of retrograde condensation as a result of the reservoir pressure falling below the dew point pressure of the hydrocarbon gas in the reservoir.

Past studies in the use of wettability alteration to tackle the problem of retrograde condensation in a gas condensate reservoir system have had three main focuses; experimental studies to develop chemical modifiers that will effectively imbibe to the surface of the rock and alter the wettability of the pore walls, studies to ascertain the most effective wettability treatment in gas condensate reservoirs given other fluid and reservoir factors, and analyses of field application of wettability alteration treatments. Most of the recorded field applications failed even though they recorded success at the experimental stage of their studies. Little to no study has gone to investigating what factors contributes to the success or failure of wettability alteration treatment in the field.

1.1 PAST APPROACH IN REMOVING CONDENSATE BLOCKAGE.

Past efforts to tackle the problem of condensate blockage commonly observed in gas condensate reservoir involves gas recycling, solvent injection, hydraulic fracturing, etc. to improve gas and condensate mobility into the wellbore. The objective of these methods is to improve gas productivity by creating favorable flow conditions for the gas. This is achieved by lowering the dew point pressure and viscosity of the near-wellbore in methods such as gas-injection, huff-and-puff, and solvent injection. Hydraulic fracturing helps remove condensate blockage and improve the flow of gas by increasing the near-wellbore permeability.

1.1.1 Solvent injection

The injection of solvent helps to restore gas productivity in a damaged reservoir by decreasing the gas-condensate interfacial tension, lowering the dew point pressure of the gas hence converting some of the formed condensates back to the gas phase. The most commonly used solvent in the field is methanol. Asgari et al. (2014) utilized cubic plus equation of state to study the use of methanol to treat condensate blocking in limestone rock in the laboratory. Methanol treatment successfully increases gas relative permeability by a factor of 1.12 and 1.64 and reduce two-phase pressure drop for the two limestone cores tested. In addition, they found out that post-treatment gas relative permeability is directly correlated with initial water saturation. Al-anazi et al. (2005) and Sayed et al. (2016) attributed the methanol displacement of condensate banking to the multi-contact miscible technique. Asgari et al. (2014) studied the role of condensate banking in gas relative permeability reduction and established that in a carbonate reservoir, gas relatively could be reduced up to 80% of the initial due to liquid blockage but the relative permeability could be increased by a factor of 50% with methanol injection. (Sayed and Al-Muntasheri 2016).

Another solvent commonly used in mitigating condensate banking in gas condensate production remediation effort is Isopropyl alcohol. Bang et al. (2010) investigated the use of Isopropyl alcohol in condensate blockage removal and concluded that the solvent can lower the dew point pressure the reservoir gas, hence increasing the gas production. The injection of solvent has an added benefit over pressure-support through gas cycling or hydraulic fracturing because there is little to no damage associated with this method (Sayed and Al-Muntasheri 2016).

1.1.2 Gas injection

This treatment method involves the re-injection of part of the produced gas into the reservoir to sustain the relative permeability of gas, and lower the dew point pressure (Sanger and Hagoort, 1998; Hoier et al., 2004). Produced gas re-injection can improve the condensate recoveries considerately. However, the demand and economic value of natural gas made it re-injection an expensive method (Sayed and Al-Muntasheri, 2016). Nitrogen gas (N2) and Carbon dioxide (CO2) are commonly utilized as alternatives to natural gas (Sepehrinia and Mohammadi, 2016). Marokane et al. (2002) investigated the use of one-time gas injection over huff and puff type injection. The study focused on two fundamental issues: the optimum time of commencing gas injection and the optimum volume that should be injected to restore well productivity. The optimal start of gas injection varies with fluid type, for rich gas, the start of injection should coincide with when the average reservoir pressure is above the maximum liquid dropout pressure. Injection of gas to improve well deliverability in gas condensate reservoirs but doesn’t result in lasting solution as they do not solve the underlying problem fundamentally (Yongfei et al., 2018). The shortcoming of CO2 injection is that it is a temporary solution. To use CO2 injection for optimizing gas productivity in gas condensate reservoir, the injection needs to be repeated frequently (Hassan et al. 2019).

1.1.3 Hydraulic fracturing

Hydraulic fracturing has been suggested as a possible stimulation approach to tackle the condensate blocking problem in gas condensate reservoir. The paths created during fracturing operation helps to delay the onset of condensate formation as it slows down pressure drop at the near-wellbore and will also create a favorable conduit for production of condensate (Hassan et al. 2019). Khan et al. (2010) presented a successful use of hydraulic fracturing to improve gas production by a factor of three in a field that has been experiencing a significant reduction in gas production and increased condensate production. One main shortcoming of hydraulic fracturing is that the fact that the true geometry of the fracture is often unknown makes this approach undesirable. While the fracture will cause the condensate to flow, it will also create a further drop in pressure hence the condensate problem will re-occur. Hydraulic fracturing can increase the contact area between reservoir fluids and solids, which can postpone the problem of condensate dropout but often incurs formation damage in the form of skin (Noh and Firoozabadi 2008).

1.1.4 Horizontal drilling

Horizontal drilling improves gas production due to the increased contact angle between the reservoir, the well and distribution of pressure drop across the large area of contact. This delays the formation of condensate at the near-wellbore region and the effect of pressure drop becomes less significant (Hassan et al 2019). A drawback to the use of horizontal well to optimize production from a gas reservoir with condensate blockage is the high cost of drilling of horizontal wells relative to vertical wells. Also, it is not a permanent solution. It only delays the formation of condensate and after a period of depletion, reservoir pressure falls below the dew point and the condensate accumulation returns (Hassan et al. 2019).

1.2 PERMANENT WETTABILITY ALTERATION.

Wettability alteration involves the use of specialized chemicals to alter the wetting state of the reservoir from the default liquid wetting state to a desirable wettability. The liquid wetting nature of the gas reservoir surface made it impracticable for viscous forces only to ensure gas deliverability once the pressure falls below dew point pressure. Hence, the need for altering the wettability of the wellbore region to ensure the flow of gas through the reservoir.

1.2.1 Experimental studies

Li and Firoozabadi, (2000a and 2000b), published the earliest works in the use of wettability alteration as a solution to condensate blockage in a gas reservoir. (Li and Firoozabadi. 2000a) use a simple 2-D representation model of porous media to assess the impact of wettability alteration on relative permeability of gas and critical condensate saturation. The study established that altering wettability to gas wetting increases the relative permeability of gas and reduces the critical condensate saturation significantly. Li and Firoozabadi (2000b) built on the findings of the former study to establish that the wettability of a porous media can indeed be changed from liquid wetting to gas wetting. Two chemicals (FC722 and FC754) were used to treat Berea sandstone and Kansas chalk in the laboratory. FC722 successfully altered the wetting of the cores to gas wetting while FC754 altered the wetting to intermediate gas wetting. The studies established that deliverability of a gas-condensate reservoir is related to the relative permeabilities of the phases present and can be improved by permanently altering the wettability of the porous media from preferentially liquid wetting to intermediate gas wetting. Since then, many other studies have been carried out to explore the promising stimulation approach for gas condensate reservoir system. Tang and Firoozabadi. 2002 built on earlier studies (Li et al, 2000a and Li et al 2000b) to examine the pre and post-wettability treatment mobility of the gas and liquid phases. FC759 and FC722 polymers were used to treat Berea and Chalk samples cores to intermediate gas wetting and it was observed that liquid and gas mobility increases significantly.

Fahes and Firoozabadi. 2005 studied the wettability alteration of two sandstone cores at high temperature. The permeabilities of the cores are 10 md and 600 md respectively and nine new chemicals were tested for their suitability for high-temperature wettability treatment in this study. it was discovered that wettability alteration can also increase liquid mobility at a temperature as high as 140^0C and the effect of chemical treatment on liquid mobility is more pronounced in a gas -water system. Alteration of the wettability of core samples from Dongu gas condensate field in China was carried out by Liu et al. 2006. The permeability of the core ranges from 0.054 - 0.096 md, and a novel chemical was used to treat the core samples. A spontaneous imbibition test shows that the relative permeabilities of the post-treated core samples have increased significantly, the residual water saturation decreased by about 15% and the novel chemical was thermally stable at 170^0C.

Zhang et al (2014) studied the pre and post-wettability alteration treatment mobility of water, oil and gas phase. The unsteady state displacement test was used to measure the liquid mobility before and after the treatment and was noted that the water and gas phase relative permeability increased significantly indicating that the wettability has been altered from liquid wetting to gas wetting. The residual oil saturation fell from 0.418 to 0.316 of the pore volume. Also, residual water saturation decreased from 0.45 to 0.35 of the pore volume while the gas phase relative permeability at the residual oil saturation increased to about twice that before treatment.

A closely related phenomenon to condensate blocking in a gas condensate reservoir is water blocking often caused by the invasion of an aqueous phase into the reservoir during operations such as drilling, fracturing, and acidizing. The capillary pressure holds the water within the pore of the reservoir and significantly lowers the gas mobility. Noh and Firoozabadi (2006) developed a multifunctional surfactant to treat core samples from a reservoir with water blocking issues. Spontaneous imbibition tests with decane and water show that the treatment significantly reduces liquid saturation in the cores. Water saturation reduces between 40 – 90% across all the test carried out and it was noted that increasing the concentration of the novel treating chemical does noticeably reduce water imbibition. Li and Zhang (2011) also studied the use of wettability alteration to improve production from gas well encountering invasion of water into production zones. A dual-layer core model was used to simulate gas and aquifer zones in a reservoir. The wettability of the gas layer was altered to preferentially gas wetting and the study established that water invasion into the gas zone was significantly lowered and the start of invasion time considerably delayed. Penny et al. (1983) leverage the strength of hydraulic fracturing by adding wettability altering surfactant into the fracturing fluid for stimulation of gas-water-rock system. The post cleans up production established that production from the well increases by 2 to 3 times that of field average.

1.2.2 Simulation Studies

Delavarmoghaddam and Zitha (2009) used a radial prototype model in CMG simulation software to examine wettability alteration in retrograde gas condensate reservoir. The model consists of 250 grids with 33 blocks in the radial direction. Each wettability state was defined by a relative permeability. The wettability treatment involves introducing a new relative permeability to the proposed treatment area within the reservoir. The simulation was repeated for reservoir permeability of 1, 10, and 100 md to examine the influence of absolute permeability on wettability alteration. It was discovered that condensate accumulation starts further from the wellbore for the higher permeability reservoir. Also, initial water saturation of the reservoir will also affect the enhancement of well deliverability from wettability alteration – the more the connate water saturation within the pores of the reservoir, the lower the effectiveness of wettability alteration treatment. The study also established a lean reservoir gas would benefit more from wettability alteration than rich reservoir gas as it allows for condensate accumulation at reservoir region closer to the wellbore.

In the simulation study by Zoghbi et al. (2010) and Ali et al (2019), in addition to studying the effect of reservoir permeability on well productivity enhancement after wettability alteration, effect of reservoir pressure and treatment radius was also examined. Similar radial gas condensate reservoir to Delavarmoghaddam et al. (2009) was developed using the builder module of CMG and the fluid types were developed using the WINPROP module of CMG. The study established that well deliverability enhancement was more pronounced for the low permeability reservoir as high permeability reservoir will likely experience condensate accumulation beyond the treatment region. The study shows a mixed result when the treatment radius was increased from 15 ft. – 30 ft. which indicates that increasing the treatment radius does not automatically imply better well deliverability.

Ajagbe et al. (2018) and Weiss. (2017) built on the works of (Delavarmoghaddam and Zitha. 2009) and (Zoghbi et al. 2010). The studies included additional fluid type whose condensate yield value is between that of lean and rich reservoir gas. Also, two reservoir sizes were utilized in these simulation models and the well deliverability enhancement was estimated in monetary value considering the cost of drilling and completion, cost of production, and cost of treatment. The studies established that lean gas reservoir is not a good candidate for wettability alteration treatment, low permeability reservoir is a better option wettability alteration treatment and a reservoir with high permeability can only be a considerable option when it has large drainage area, and medium gas reservoir appears to be the best candidate for wettability alteration treatment.

1.2.3 Field Application

Liu et al. (2008) designed a pilot test for field application of wettability alteration to improve production in a gas-condensate reservoir. Building on the promising results of an earlier experimental study, a gas production well in a basin in china was selected for treatment with permeability < 0.1 md, temperature of 3200 F, initial reservoir pressure of 9689 Psi, and well depth of 14,823 ft. It is to be noted that large scale fracturing was carried out on this well initially, but the production was not significantly improved. The field trial involves the injection of a fluorocarbon (WA12) surfactant with a characteristic short but strong carbon-fluorine bond and has high surface activity, high thermal stability, high chemical stability and hydrophobia, oil phobia properties. 189 barrels of 1% wt. of WA12 was introduced into the lower layer of one of the wells in the field at a rate of 3.15 barrels/min. The well was soaked in the fluorocarbon for a day after which production from the well resumed. Gas production from the well improved to about 1.06 MMScf/day but declined rapidly to about 0.141 MMScf/day four days after production resumed. This was still a 200% increase in production rate when compared to gas production before wettability alteration. The study attributed the observed rapid decline in production to the high viscosity of the fluid, low permeability, high fluid viscosity, high paraffin content of the crude oil, an insufficient amount of chemical injected, etc. The field trial was carried out in the wintertime and 100 tubings were retrieved from the well filled with almost solid crude oil.

Weiss et al. (2009) studied the use of wettability alteration on a natural gas storage aquifer in northern Illinois. The aquifer is strongly water-wet and is believed to retain water at it pores due to capillary pressure that hampers well deliverability during production and injection of gas during the filling cycle. The depth of the aquifer ranges from 1770 to 1930 ft., a well spacing of about 660 ft., average porosity of 18%, average permeability of 400 md and bottom-hole temperature of 82 F. Three wells were chosen to serve as injection wells and other three wells were selected as control wells. The treatment involves the injection of 1000 lb. of about 4% Tomadry N-4 solution into the 3 injection wells following a favorable prior lab result. The aquifer has a discovery pressure of 747 psi and a maximum surface injection pressure of 845 psi and initial connate water saturation of 30%. After treatment, only one of the three treatment wells experienced a rate higher than normal, while all three wells produced oily waxy fluid was produced with a strong surfactant smell that affects one of the production systems. Also, a freezing problem was experienced at the separator and gas gathering system from one of the wells. At the end the following year, the effectiveness of the wettability treatment was assessed, and it was observed that production from 2 out of the 3 wells increased by 33% when compared to production before treatment.

In other field applications, Butler et al. (2009) recorded a 3-fold increase in the flowrate of post wettability alteration treatment of sandstone after about 180 days. However, Restrepo et al. (2012) recorded a temporary enhancement in well deliverability for less than 25 days following wettability alteration.

Chapter 3: Research Methodology

3.1 RESERVOIR MODEL.

The reservoir and fluid models used in this study were built using the Builder module and Winprop module of the CMG software respectively. Values of wellbore radius, reservoir radius, porosity, and compressibility were consistent with that of earlier works such as Zoghbi et al. (2010), Weiss. (2017), and Ajagbe et al. (2018). The reservoir model and other input parameters are summarized in Table 1.

Table 3-1 Reservoir properties

Property	Value
Reservoir Radius, ft.	15,000
Wellbore Radius (Innermost Grid Radius), ft.	0.33
Reservoir Top Depth, ft.	8,000
Reservoir Thickness, ft.	70
Initial Reservoir Pressure, psi	5,500
Porosity, %	12
Water Saturation, %	0
Formation Compressibility, psi^{-1}	$1x10^{-6}$
Minimum Allowable Bottom Hole Pressure, psi	2,000

The model of the reservoir used is gotten from Weiss. (2017). A 15,000 ft. radius reservoir with a vertical well at the center. In order to ensure some of the fluid cases during the simulation would fall below the dew point, a minimum bottom hole flowing pressure constraint of 2000 psi was imposed on the well. Considering the fact that leaner fluids and higher permeability would require higher flow rate, the flow rate for each run was selected based on once that would ensure constant production rate in the first few years of production (2 – 3 years) before decline begins and it should be noted that the flow rate is same for each permeability and fluid type combination.

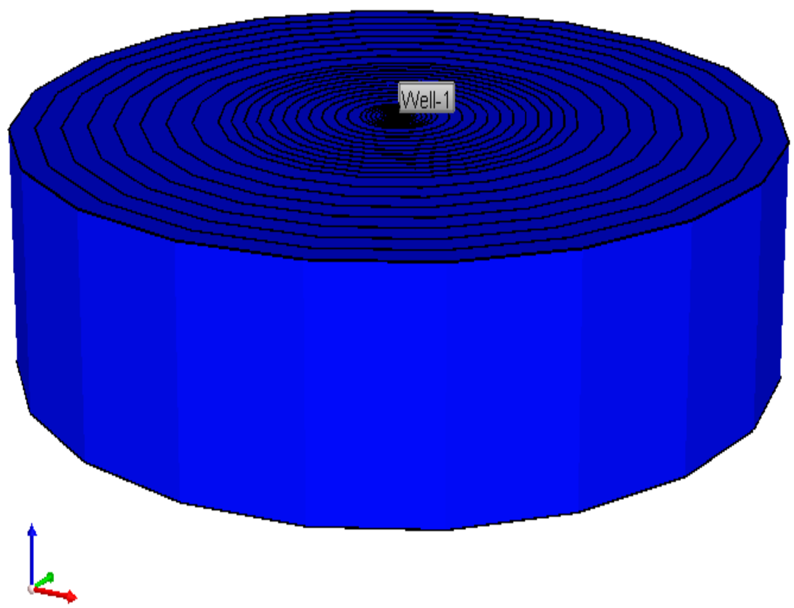


Figure 3-1. 3D representation of the CMG reservoir model used in the study

Figure 3-1. is the pictorial representation of the reservoir model used in the simulation? It can be seen that the cell with closest to the well is smallest and we move outward from the well, the width of the cell becomes progressively wider. **Table 3-2** includes the thickness of each of the 78 "shell-like" cells ranging from nearest to the wellbore at the top to furthest from the wellbore at the bottom.

To create a zone of modified relative permeability in order to impose a zone of altered wettability within the reservoir, we followed the approach described by Weiss. (2017). A sector within the reservoir would be assigned a different relative permeability curve from the rest of the reservoir, which would remain strongly liquid wet through the simulation. **Fig. 3-2** depicts the 3 sets of relative permeability the three of relative permeability used in this study; strong liquid-wetting, strong gas-wetting, and intermediate gas-wetting. Endpoint saturations are consistent with literature as well as the Corey exponents that were used to influence the curvature (Corey 1954).

Table 3-2. Grid cell dimensions

Cell Number	Number of Cells	Thickness, ft.	The distance of Outer Cell Edge from Wellbore, ft.
1	1	0.1	0.1
2	1	0.2	0.3
3	1	0.3	0.6
4	1	0.4	1
5 – 8	4	0.5	3
9 – 15	7	1	10
16 – 25	10	2	30
26 – 35	10	3	60
36 – 43	8	5	100
44 – 45	2	30	160
46 – 51	6	40	400
52 – 53	2	50	500
54 – 55	2	100	700
56 – 59	4	200	1,500
60 – 70	11	500	7,000
71 – 78	8	1,000	15,000

For the intermediate gas-wetting and strong gas-wetting cases, the Corey exponents were 2 and 2.5 for liquid and gas respectively. For the strong-liquid wetting case, the exponents were 4 and 2.5 for liquid and gas respectively (Zoghbi et al. 2010). The strength of the wettability of a particular phase determines the magnitude of the exponents, while the end to end saturation point determines the strength of wettability of the phase i.e. if a system is strongly liquid wet the residual oil saturation would be higher.

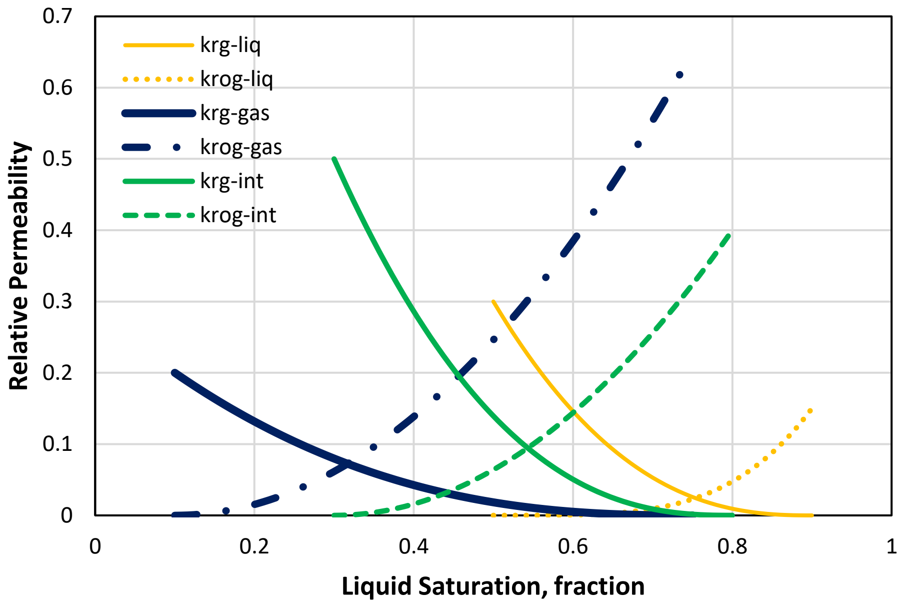


Figure 3-2. Relative permeability curves used in the study
(adapted from Zoghbi et al. 2010)

3.2 FLUID MODELS AND ROCK-FLUID INTERACTIONS.

Zoghbi et al. (2010) and Weiss. (2017) made use of an example of condensate fluid composition based on the template available in the CMG software. This study considers two additional fluid composition namely Lean and Rich, in addition to the Medium condensate examined n Zoghbi et al. (2010).

There are different metrics to quantitatively classify condensate reservoir, among which are; gas-oil ratio (GOR of 5,000 to 100,000 Scf/STB), (above 45° API), the weight fraction of components heavier than hexane (C7+ fraction), or even qualitatively by the color of the produced fluids (Coskuner 1999). The criterion used in this study as the basis for differentiating fluid models was the yield. The yield of fluid is expressed in units of barrels produced condensate per million cubic feet of gas. In that regards, a rich condensate will have a yield is greater than 150 STB/MMcf, while a lean condensate will have a yield of less than 50 STB/MMcf. The medium condensate will have a yield that lies between that of rich and lean condensate. It should be noted that there is no hard-set rule for this classification scheme and the yield of a condensate reservoir may range anywhere from 7 to 333 STB/MMcf (Shi et al. 2009 and Weiss 2017). The condensate yield of the fluids considered in this study includes 40 STB/MMcf for lean fluid, 95 STB/MMcf for medium fluid and 150 STB/MMcf for rich fluid.

Figure 3-3 shows the summary of the relative proportion of the three components that describe the reservoir fluid model. From the bar chart, it appears the values of the fluid chemical composition are somewhat similar, it should be noted that even slight change in the chemical composition of this fluid would alter the phase behavior of the overall system. **Table 8-8** shows the data used to generate the relative permeability plot. In addition to the CMG condensate template used in Zoghbi et al. (2010), lean and rich fluid compositions were from literature and modified to produce the best comparison and demonstrate the widest range of behavior. The most significant difference between the fluid compositions is the amount of methane which decreases as we move from lean to rich fluids. The properties of the C7+ used in this study are summarized in **Table 8-7**, with the proportion of C7+ increasing as the fluid becomes richer. Additional properties of the three reservoir fluids used in this study are summarized in **Table 8-4, 8-5** and **8-6.**

The phase envelopes for the three reservoir fluid models can be seen in **Fig. 3-3**. The difference in the fluid properties of the fluid models can be clearly identified from the phase diagram. As expected, the rich composition in yellow has the highest cricondentherm, cricondenbar and critical temperature and pressure of the three types, while the lean phase envelope in dark blue has the lowest values for these properties.

The reservoir temperature of 220 ^{0}F is shown as a vertical grey broken line to indicate the isothermal pressure depletion path that the model goes through before reaching the minimum bottom hole pressure constraint of 2000 psi. The fact that the critical points of all the three fluid models fall to the left of the reservoir temperature line indicates that the composition of the produced fluid commences as a gaseous phase.

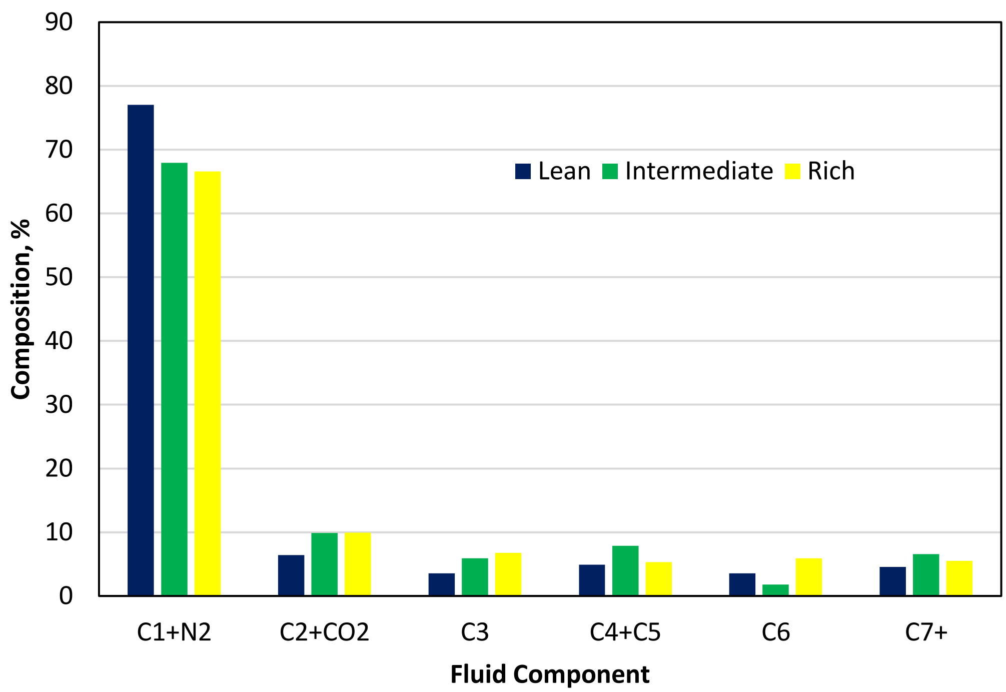


Figure 3-3. Composition of three reservoir fluids used in the study (adapted from Weiss 2017)

It is important to examine the liquid dropout curve of each fluid to access the validity of the WinProp models from CMG. **Figure 3-4** shows the result of a constant composition expansion (CCE) test at the reservoir conditions. In a laboratory CCE test, a fluid sample is placed in a cell under high pressure and temperature. Gradually, the pressure in the cell is lowered, usually by the movement of a piston, and the resulting volume fraction of liquid in the cell is recorded. This process is repeated many times at small pressure increments.

If the test is designed to span the range in pressure from the reservoir to surface, it will accurately predict phase volume fractions that can be expected at the surface when the well is produced (Weiss 2017). The WINPROP software simply models this process. Moving from reservoir pressure at the bottom right of the plot in **Fig. 3-4**, the figure shows that the rich composition has the first abrupt introduction of a fluid phase to the mixture, followed by the medium case and the lean case. As the pressure continues to fall, the volume fraction of liquid drops to a value near zero, which falls in line with the trends seen in the phase diagrams.

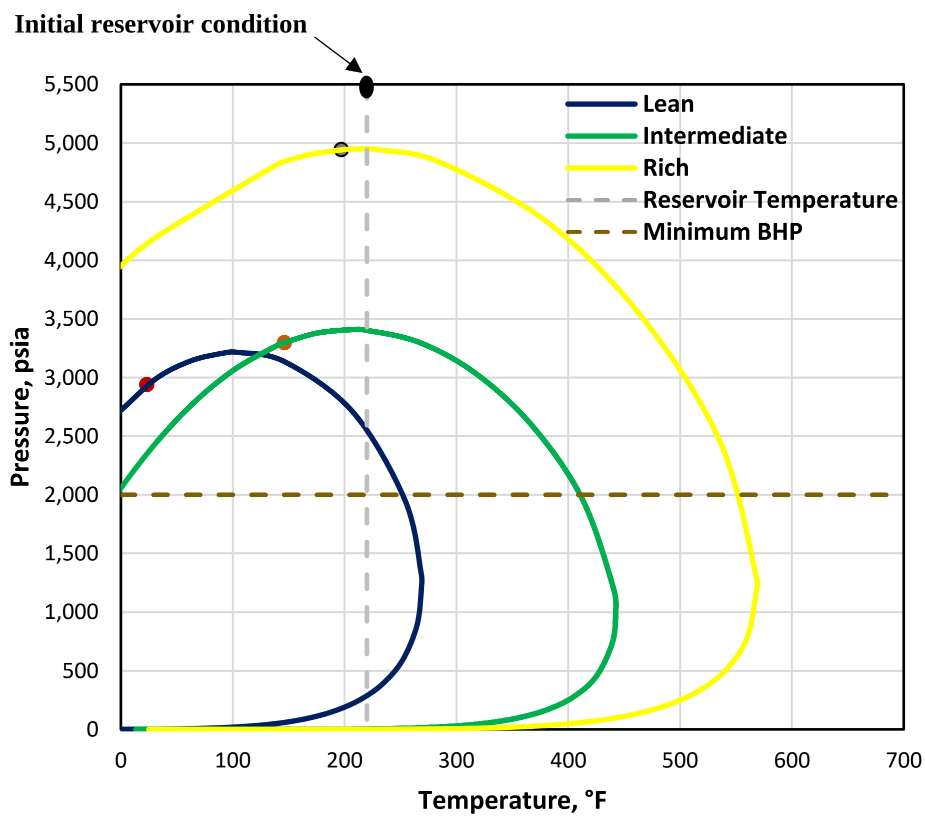


Figure 3-4. Phase envelopes of the three WINPROP fluid models used in the study

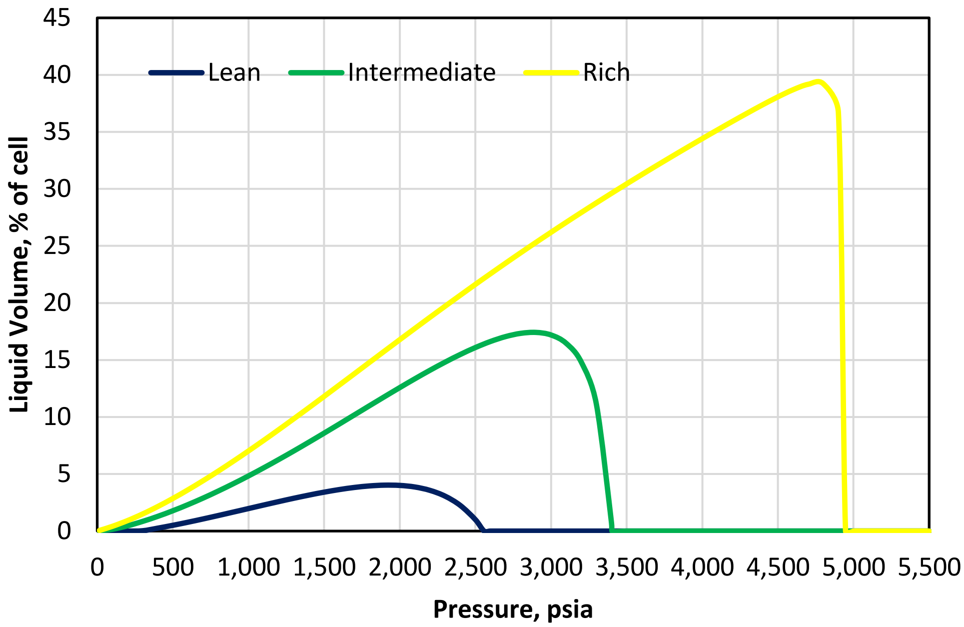


Figure 3-5. The plot of liquid dropout for three reservoir fluids using simulated CCE test

3.3 NODAL ANALYSIS.

Nodal analysis was used to determine the equilibrium flow condition of the wells in our simulation model in Chapter 6. The nodal analysis is an iterative process that involves the use of the relationship between the flow rate and the bottom hole pressure of the well to evaluate the flowrate and BHP that we could observe at equilibrium conditions, considering the reservoir properties, wellbore geometry, and completion limitations. In a nodal analysis, the objective is to establish a point of intersection between the inflow performance relationship (IPR) and the tubing performance curve (TPC). The IPR is the relationship between flowrates and bottom-hole pressure that is estimated from the reservoir model while the TPC gives the bottom hole estimations from the wellbore model. In addition to estimating the optimal flow rate and flowing bottom-hole pressure, nodal analysis helps in easy identification of ways to increase the rate from the well and selection of artificial lift method.

Pipesim multiphase flow simulation software was used to estimate BHP corresponding to some selected flowrates from the wellbore model. A steady-state gas flow equation was used to calculate the flowing bottom hole pressure given the fluid and reservoir properties in the IPR. The flowrate and bottom-hole pressure were estimated from the nodal analysis were used as input to the CMG to simulate radial flow in a gas condensate reservoir.

3.4 WETTABILITY ALTERATION PERFORMANCE EVALUATION.

In laboratory experiments, the use of contact angles of liquid drops on rocks sample is used to evaluate successful wettability alteration treatment. An untreated rock sample is expected to quickly imbibe the wetting liquid droplets hence should have a very low angle of contact with rock surface while the imbibition of liquid drops on a treated rock surface is expected to be poor hence, the contact angle is high condensate drop out. In addition, spontaneous imbibition test is also used to quantify the effectiveness of wettability alteration. The spontaneous imbibition test evaluates wettability alteration by estimating the change in water saturation of the core samples. Change in absolute permeability of rock sample is also used to evaluate the change in permeability of the rock samples. Noh and Firoozabadi. (2008) used Nitrogen to quantify absolute permeability of untreated and treated rock samples. Al-Anazi et al. (2007) used scanning electron microscopy to assess wettability alteration at the pore level, condensed water vapor forms a spherical droplet on the sand grain which indicates the wettability of the grain has been altered to be less water wet. A test complimentary to the contact angle test is often used to assess wettability alteration at the laboratory scale is the capillary tube rise test. Zhang et al (2013) used the glass capillary tube rise to assess the wettability alteration of the rock cores by flooding them with a fluorinated polymer.

The glass tube is aged in the wettability altering chemical solution for a given period of time, after drying at room temperature the tube is inserted vertically in the liquid level. If the liquid level within the capillary tube rises, this indicates the treatment causes the tube to be strongly liquid wet and contact angle < 90, If the level is same the liquid level outside of the tube, the glass tube is said to be intermediate gas wet and contact an equals 90, if the level with the glass tube falls relative to the liquid level outside of the tube, this indicates strongly gas wetting condition and contact angle > 90.

The shortcoming of all these methods is that it does not truly reflect the permanent alteration of the wettability of the rock pores that is expected from a wettability alteration treatment. Moreover, the laboratory methods do not indicate if the wettability treatment is of economic value.

Past simulation studies investigated the effect of wettability alteration in gas condensate reservoir has used increased gas flowrate or cumulative production after a certain period to evaluate the effectiveness of wettability alteration treatment and a conclusion was drawn on effects of factors such as treatment radius amongst other factors without consideration for cost. Zoghbi et al. (2010) used increased gas and condensate rate to evaluate wettability alteration treatment while Delavarmoghaddam et al. (2002) used 10-year cumulative gas production to assess the performance of wettability treatment. The shortcoming of this method is that it assumes wettability alteration is at zero cost and it fails to answer a fundamental production engineering question – does the incremental gas/condensate production justify the treatment cost?

In this study, in an attempt to evaluate the effectiveness of the wettability alteration treatment, we carried out an economic analysis. Drilling, completion, fixed production cost, variable production cost, treatment cost was considered in the analysis. The amount of increased (or decrease) revenue that would be generated from a treated well, discounted to year zero was used to evaluate wettability alteration treatment in this case. i.e.

NPV from the treated case – NPV from the untreated case.

The major strengths of this approach are that it penalizes treatment that does not result in a substantial increase in gas and condensate production and can we easily compare the true added value from using different treatment radius.

In this case, 20-year net present value (NPV) was estimated using the average year gas and condensate rates from the well at a gas and condensate price of $2.50/MScf and $50/bbl. respectively. A drilling and completion cost of $3,500,000 per well was included in the analysis. Other cost includes a fixed cost of $10,000 per month, the variable cost of $0.5/MScf of gas produced and treatment cost is added if the well was treated.

3.4.1 Treatment cost

A radial reservoir thickness of 70 ft., 12% porosity and treatment radius of 15 ft., gives a treatment volume of about 6000 ft^3 and a treatment volume of 660 ft^3 for 5-ft treatment radius. **Table 3-3**. Shows the volumetric mix of reagents for each wettability treatment. An estimated water cost of $0.35/bbl., ethanol cost of $65.1/bbl. and surfactant cost of $500/kg was considered. The intermediate wetting treatment cost is estimated to be about $670,000, while gas wetting treatment cost stands at about $1,200,000 and treatment is assumed to be carried out at year zero

Table 3-3. Treatment mix of reagents for wettability alteration

	IW	GW
Water	63%	62%
Ethanol	36%	36%
Chemical	1%	2%

Chapter 4: Simulation Result and Discussion

This chapter presents the results from the study of wettability alteration in various combination of reservoir and fluid conditions. Wettability alteration in a reservoir containing lean fluid is examined first under bounded and unbounded drainage area and under low and high permeability. Results from wettability alteration models for medium and rich fluid under the same conditions are presented subsequently.

4.1 LEAN FLUID.

The observation that stands out for this simulation involving a gas reservoir containing lean fluid that wettability alteration to the preferential gas wetting state should be avoided regardless of the reservoir size or permeability, it does not improve the well productivity and it consistently gave a poor gas and condensate production. Factoring the cost of treatment, it is significantly n uneconomic stimulation effort for a gas reservoir. In addition, a 2000 ft. reservoir with 100 md permeability would also not be a good candidate for wettability alteration. Wettability alteration from the default liquid wetting state to any of the two other states does not have a noticeable impact of well deliverability and factoring cost of treatment, in this case, makes it an uneconomic option likewise.

4.1.1. 2000-ft reservoir

4.1.1.1 10-md permeability

In a 2000 ft. reservoir with 10 md permeability containing a lean fluid, when produced at an initial production rate of 1 MMScf/D, an Intermediate Wetting (IW) condition gives the best production performance. It results in a constant initial production rate for almost 3 years as against a liquid-wetting condition whose production began to decline sharply at just over 2 years as shown in **Fig. 4-1**. The gas wetting condition resulted in the least favorable impact on production for this combination of reservoir and fluid condition, even though its impact on production in later years is slightly better than that of intermediate wetting.

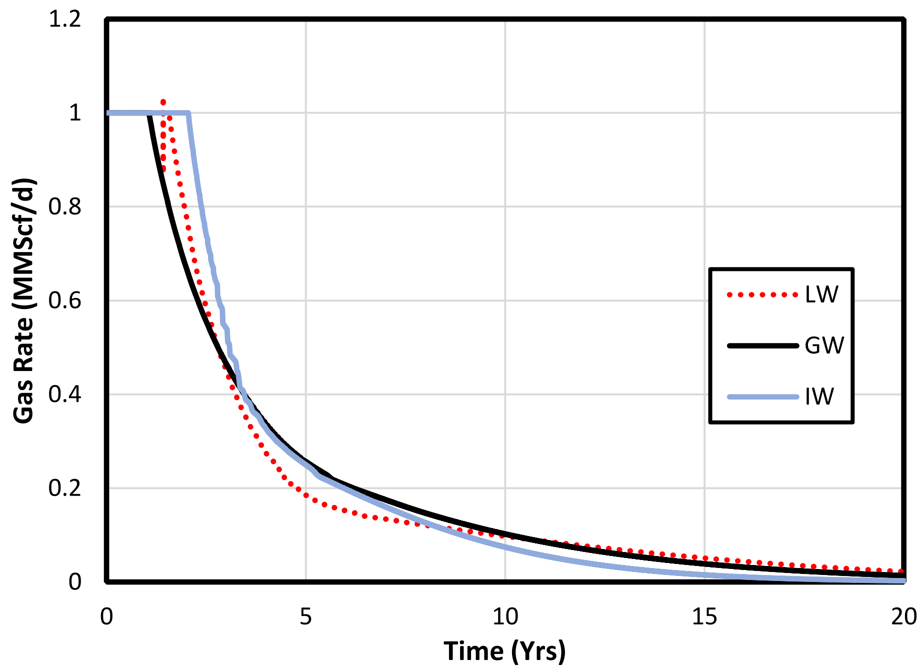


Figure 4-1. Gas Rate from a 2000 ft., 10 md. reservoir containing Lean fluid

The bottom-hole pressure in the gas wetting condition declined fastest, slowest for the intermediate condition, and as expected, approached the minimum bottom-hole pressure at about the time gas rate begins to decline from its initial production rate as shown in **Fig. 4-3**. The GOR for the intermediate wetting condition changed early and the change is more pronounced during a 20-year production for this reservoir and fluid condition as shown in **Fig. 4-2**. Cumulative production is depicted in **Fig. 4-4 and 4-5**. This result shows that the ultimate recovery under these reservoir and fluid conditions does not change, but that more recovery is expected in earlier years for the intermediate-wetting case. The value of this change in the production profile is further investigated in the economics section.

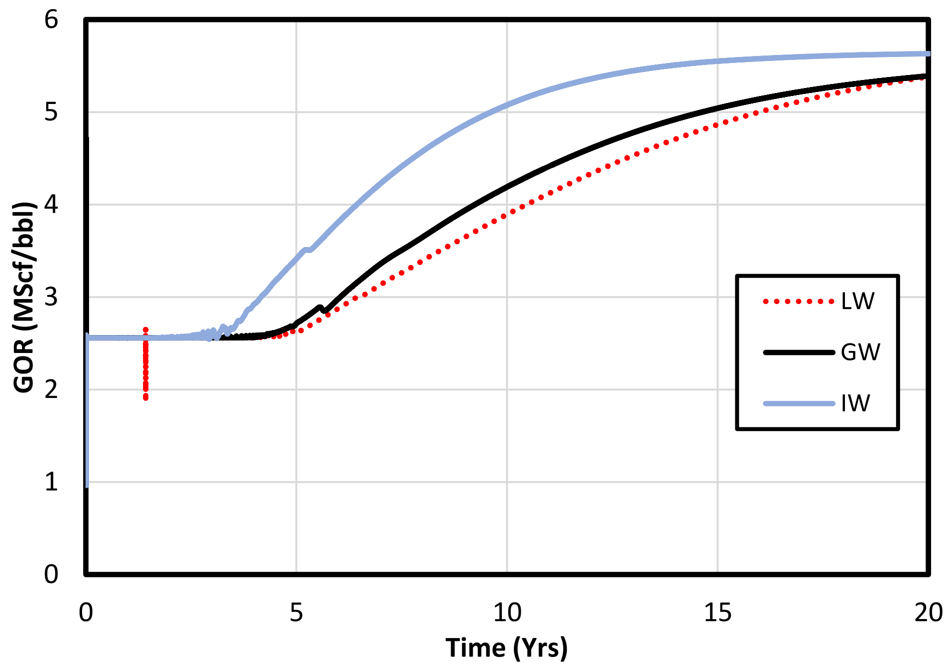


Figure 4-2. GOR from a 2000 ft., 10 md. Reservoir containing Lean fluid

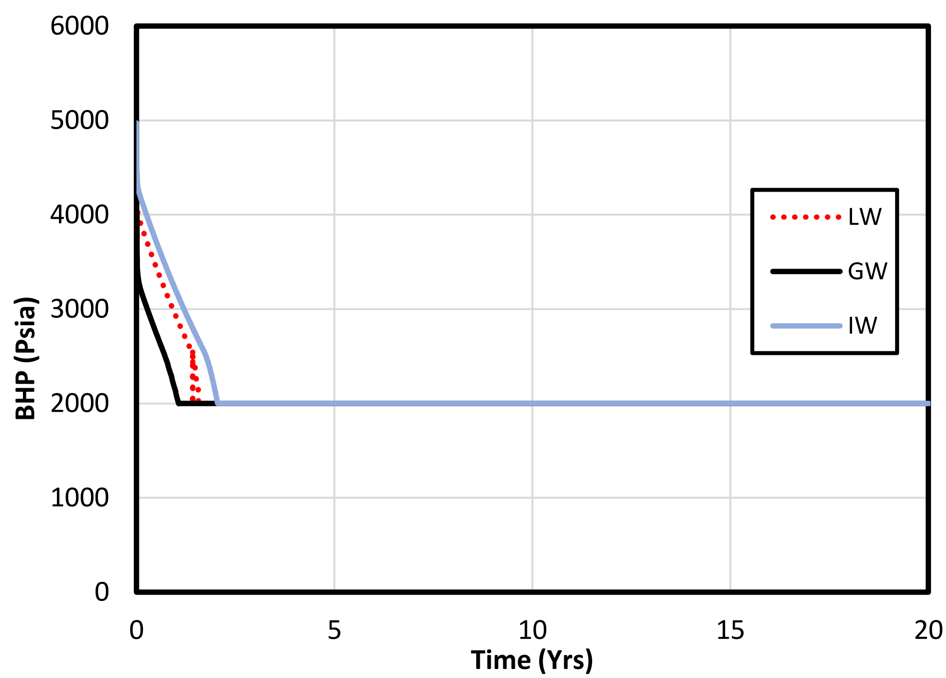


Figure 4-3. Bottom hole pressure from a 2000 ft., 10 md. Reservoir containing Lean fluid

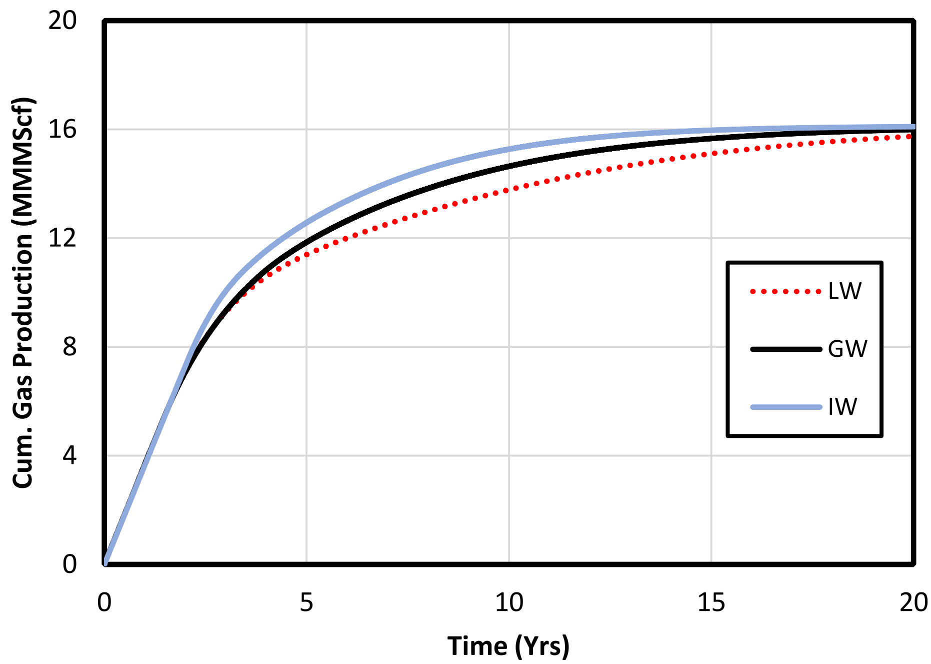


Figure 4-4. cumulative gas production from a 2000 ft., 10 md. Reservoir containing Lean fluid

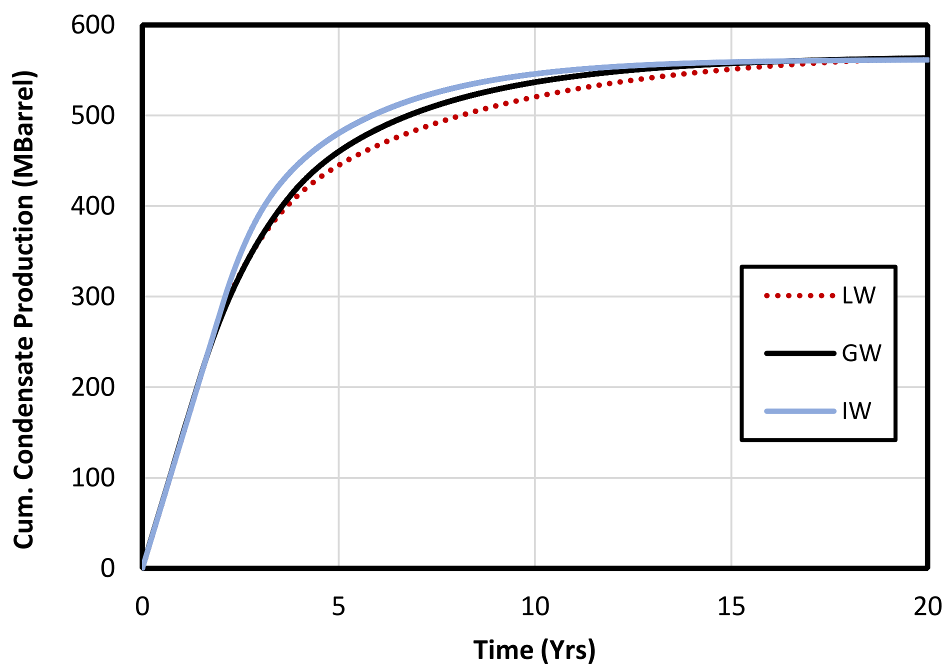


Figure 4-5. Cumulative Condensate production from a 2000 ft., 10 md. Reservoir containing Lean fluid

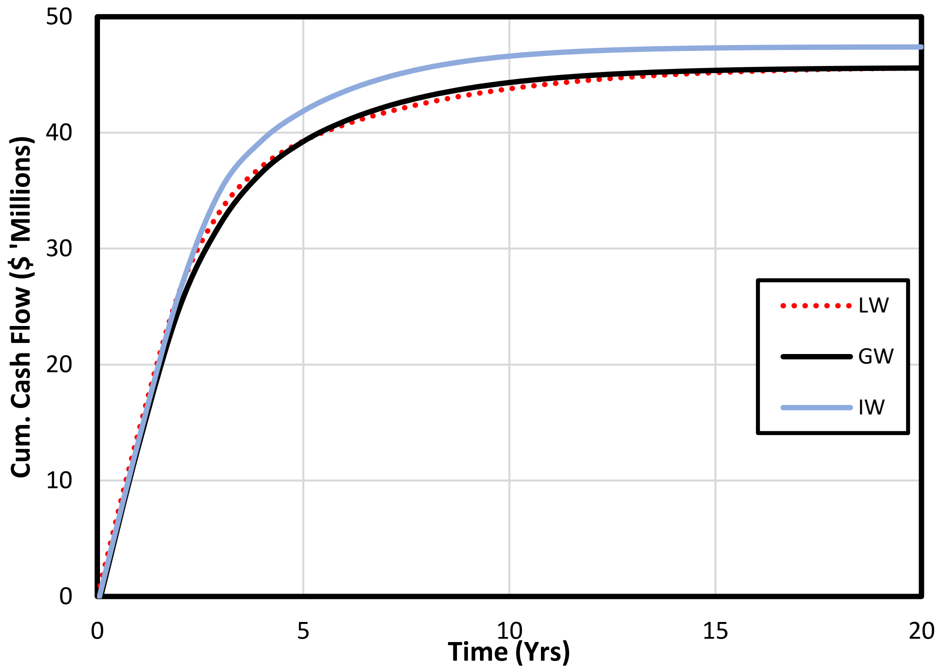


Figure 4-6. Cumulative cash flow from a 2000 ft., 10 md. Reservoir containing Lean fluid

4.1.1.2 100-md permeability

In the case of a 2000 ft. reservoir with a permeability of a 100 md containing lean hydrocarbon fluids, wettability alteration to either gas or intermediate wetting has no effect on production rate, GOR, BHP and hence cumulative gas and condensate production as shown in **Figs**. **4-7**, **4-8, 4-9, 4-10,** and **4-11**. The initial gas production rate was sustained for the same number of years and declined in a similar pattern. **Figure 4-12** shows the expected cash flow for a 20-year production for a well drilled in a 2000 ft. reservoir with a permeability of a 100 md containing lean hydrocarbon fluids. Intermediate or gas wetting will clearly lead to a loss of cash flow hence should not be considered in this case.

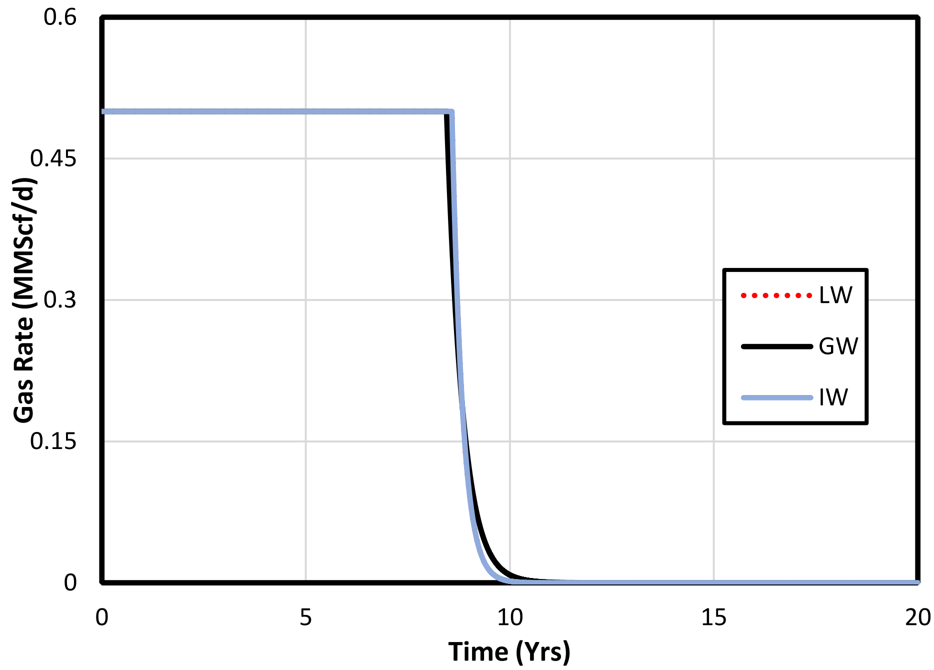


Figure 4-7. Gas Rate from a 2000 ft., 100 md. Reservoir containing Lean fluid

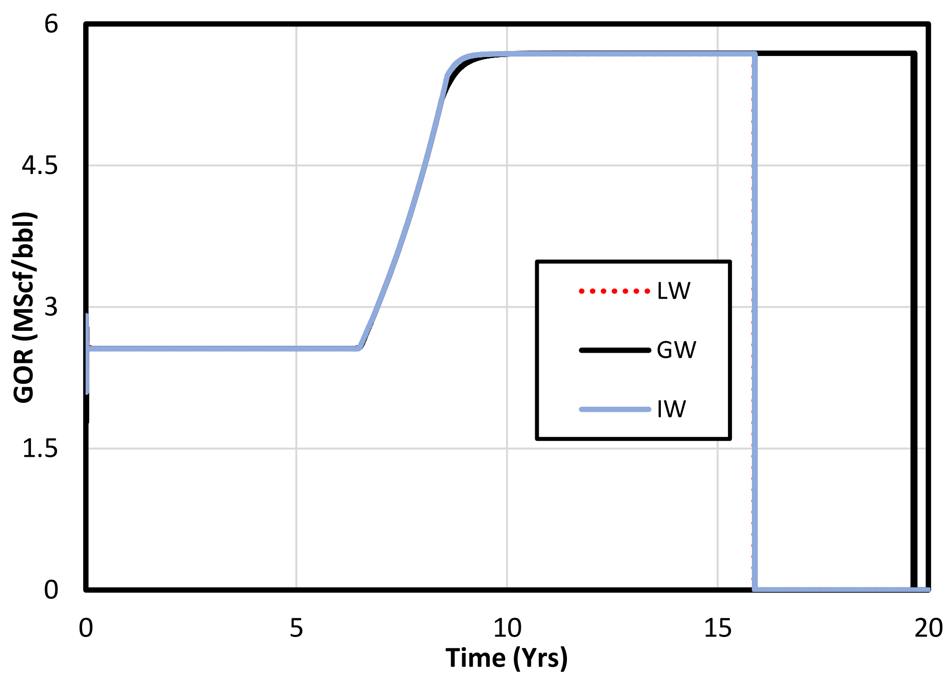


Figure 4-8. GOR from a 2000 ft., 100 md. Reservoir containing Lean fluid

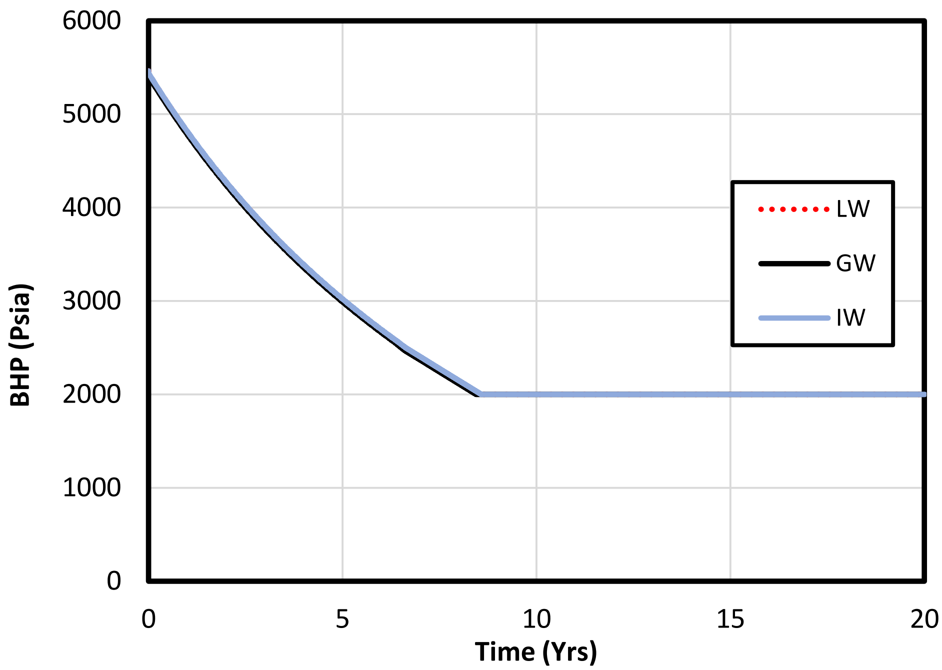


Figure 4-9. BHP from a 2000 ft., 100 md Reservoir containing Lean fluid

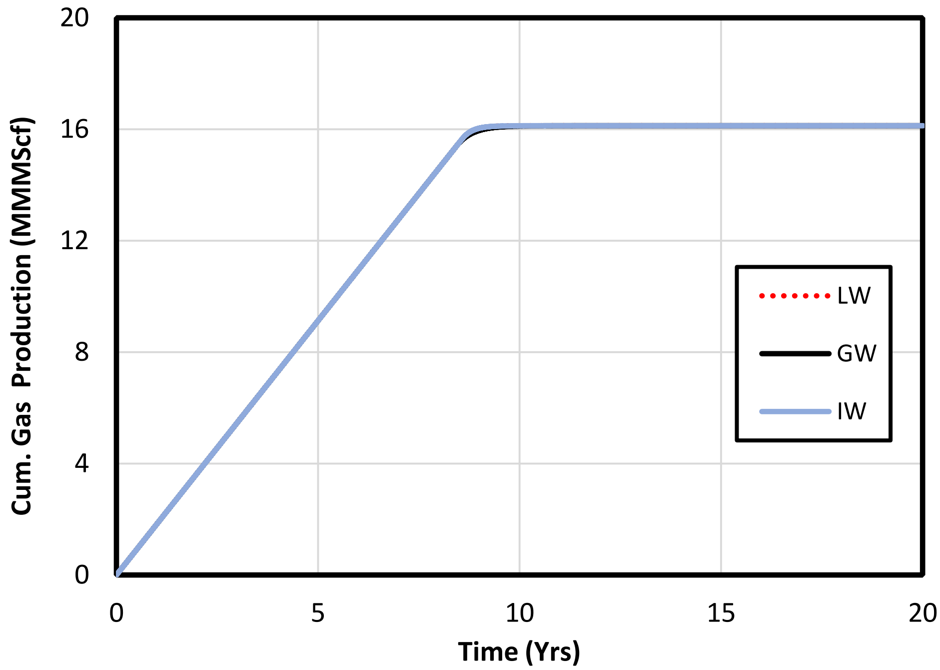


Figure 4-10. Cumulative gas production from a 2000 ft., 100 md. Reservoir containing Lean fluid

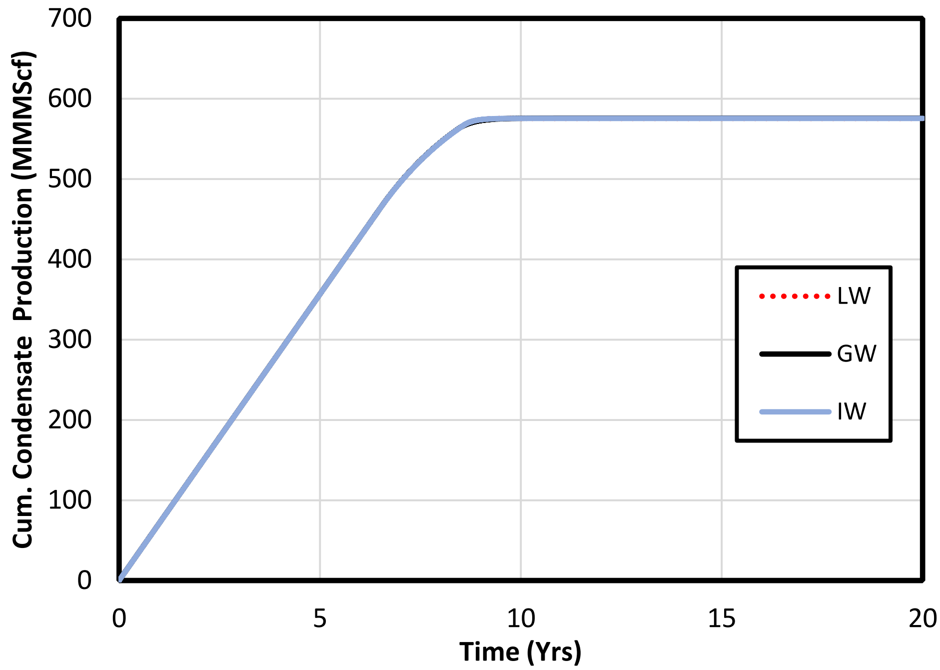


Figure 4-11. Cumulative condensate production from a 2000 ft., 100 md. Reservoir containing Lean fluid

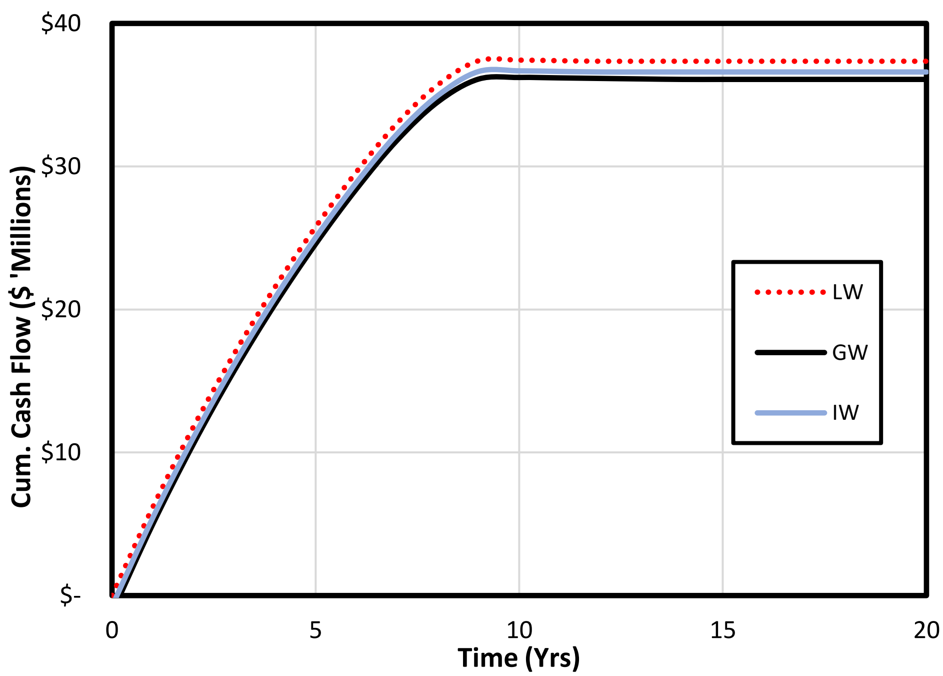


Figure 4-12. Cumulative cash flow from a 2000 ft., 10 md. Reservoir containing Lean fluid

4.1.2 15000-ft reservoir

4.1.2.1 10-md permeability

In order to eliminate the reservoir size effect, the results and conclusions discussed in section **4.1.1** are compared to the case where a 15000 ft. reservoir radius is used. At a maximum gas rate of 1.75 MMScf/D, the intermediate wetting condition sustained the initial production rate for over 15 years while liquid wetting and gas wetting condition resulted in a decline from the initial gas rate from about the third year and before the first year respectively as shown in **Fig. 4-13**. However, the GOR, in this case, did not change for the 3 wetting conditions as shown in **Fig. 4-14**.

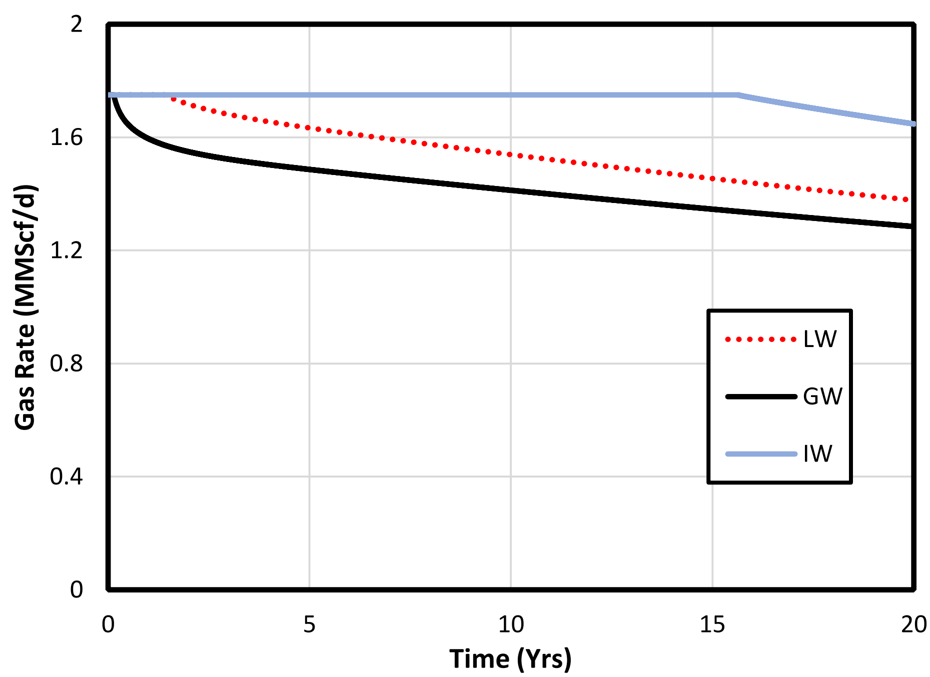


Figure 4-13. Gas Rate from a 15000 ft., 10 md. Reservoir containing Lean fluid

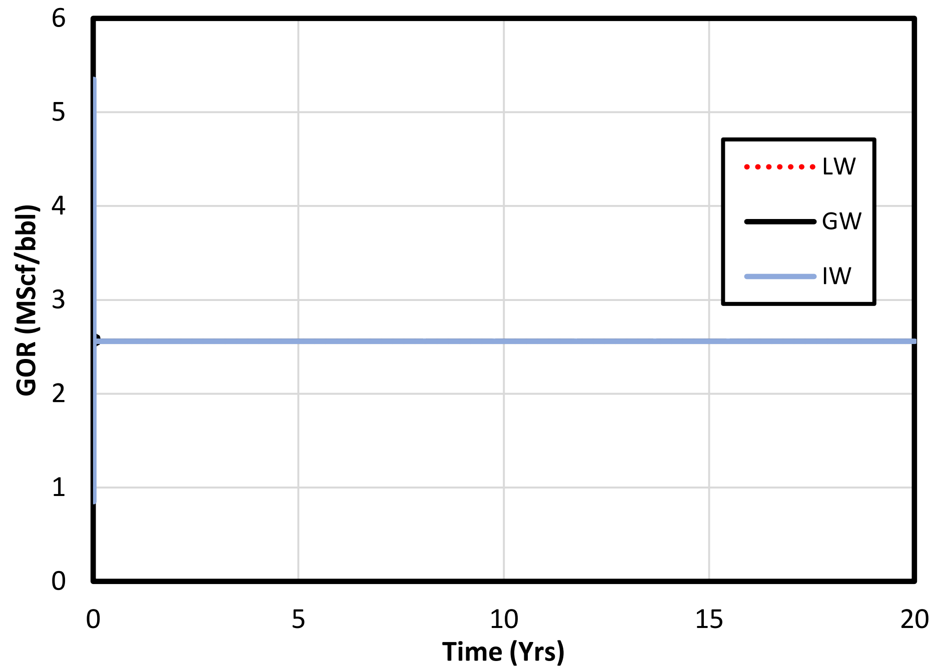


Figure 4-14. GOR from a 15000 ft., 10 md. Reservoir containing Lean fluid

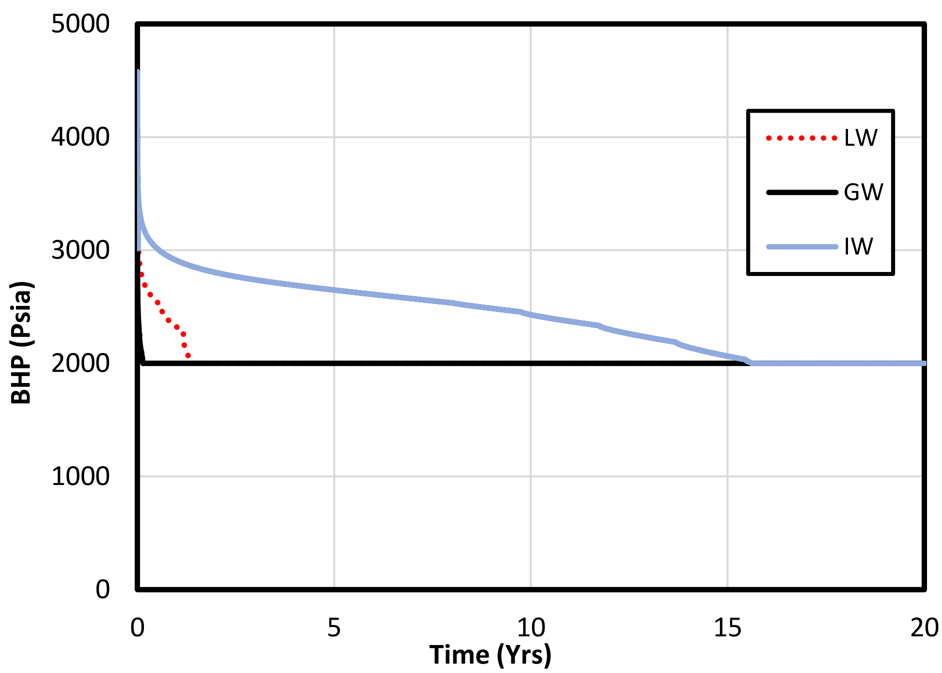


Figure 4-15. BHP from a 15000 ft., 10 md. Reservoir containing Lean fluid

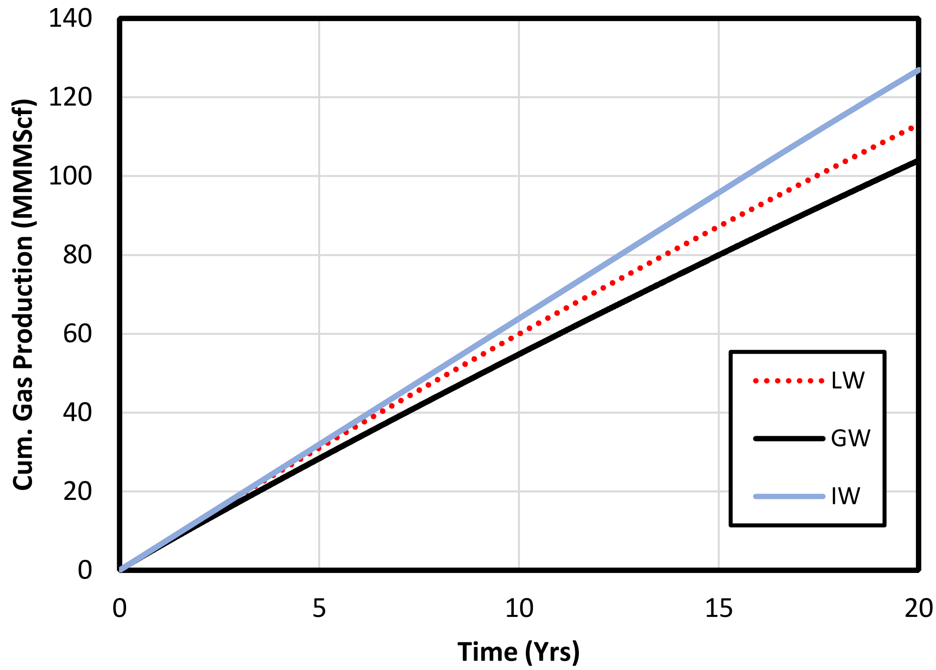


Figure 4-16. Cumulative gas production from a 15000 ft., 10 md. Reservoir containing Lean fluid

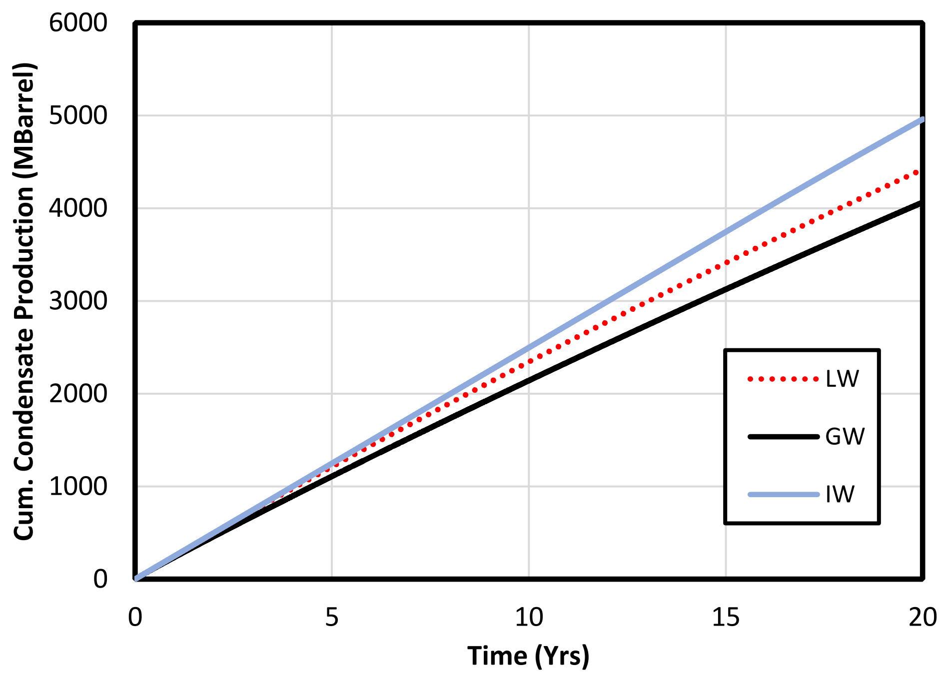


Figure 4-17. Cumulative condensate production from a 15000 ft., 10 md. Reservoir containing Lean fluid

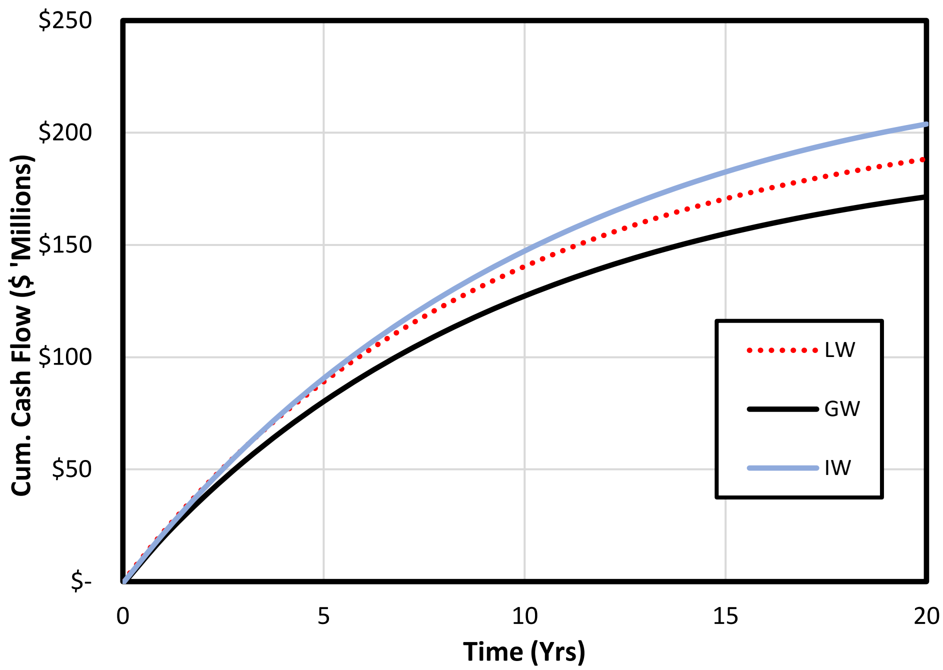


Figure 4-18. Cumulative cash flow from a 15000 ft., 10 md. Reservoir containing Lean fluid

4.1.2.2 100-md permeability

At reservoir radius of 15000 ft., permeability of 100 md. and an initial gas production rate of 14.5 MMScf/D, it was observed that the intermediate wetting condition sustained the initial production rate for almost 4 years while liquid wetting and gas wetting condition resulted in a decline from initial gas rate from about the third year and before the second year respectively. The GOR is again similar for the 3 wettability cases under this condition. The results are presented in **Figs. 4-19, 4-20, 4-21, 4-22, 4-23 and 4-24**.

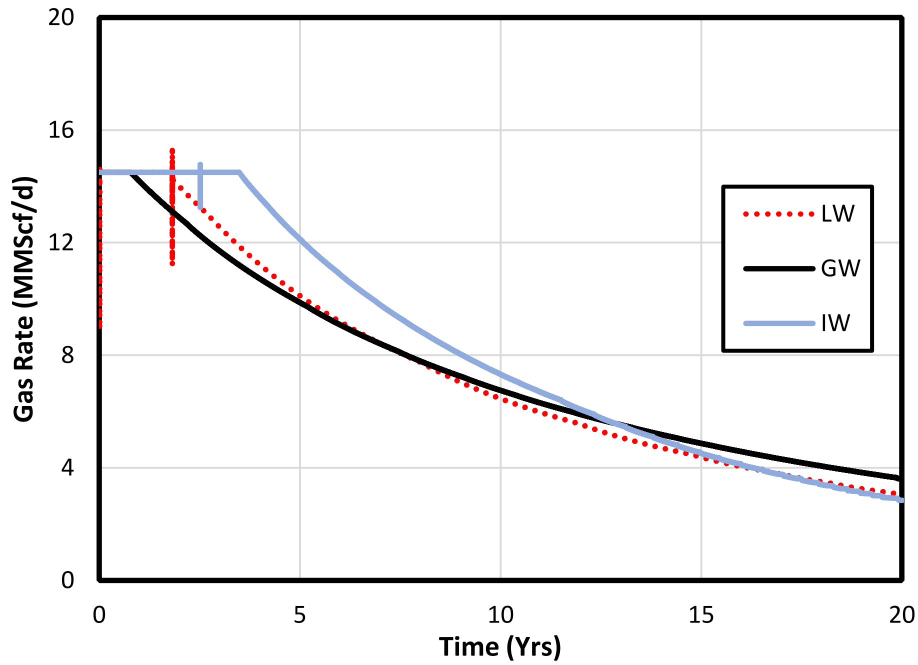


Figure 4-19. Gas Rate from a 15000 ft., 100 md. Reservoir containing Lean fluid

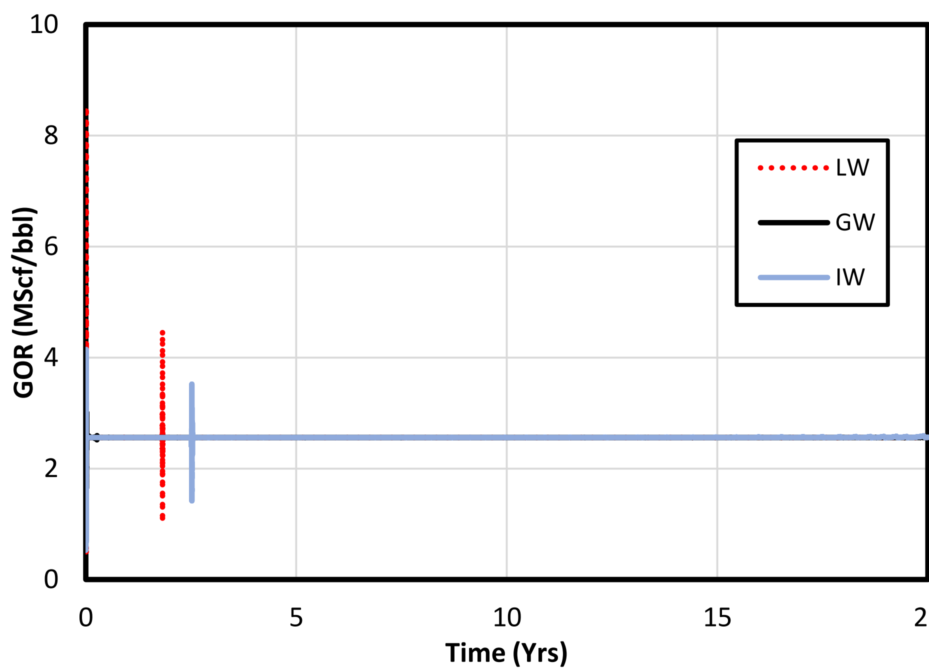


Figure 4-20. GOR from a 15000 ft., 100 md. Reservoir containing Lean fluid

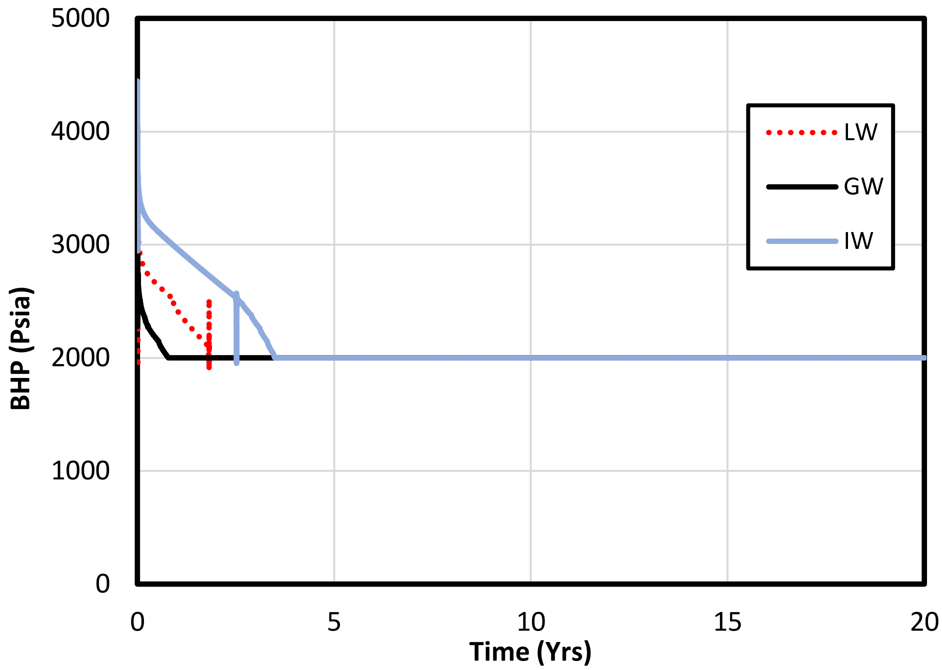


Figure 4-21. BHP from a 15000 ft., 100 md. Reservoir containing Lean fluid

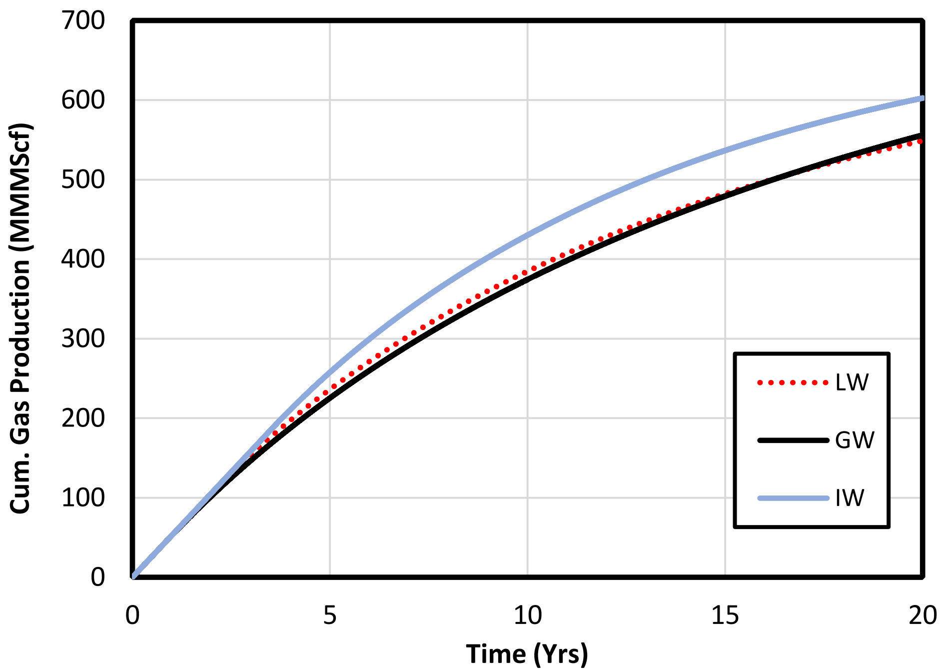


Figure 4-22. Cumulative gas production from a 15000 ft., 100 md. Reservoir containing Lean fluid

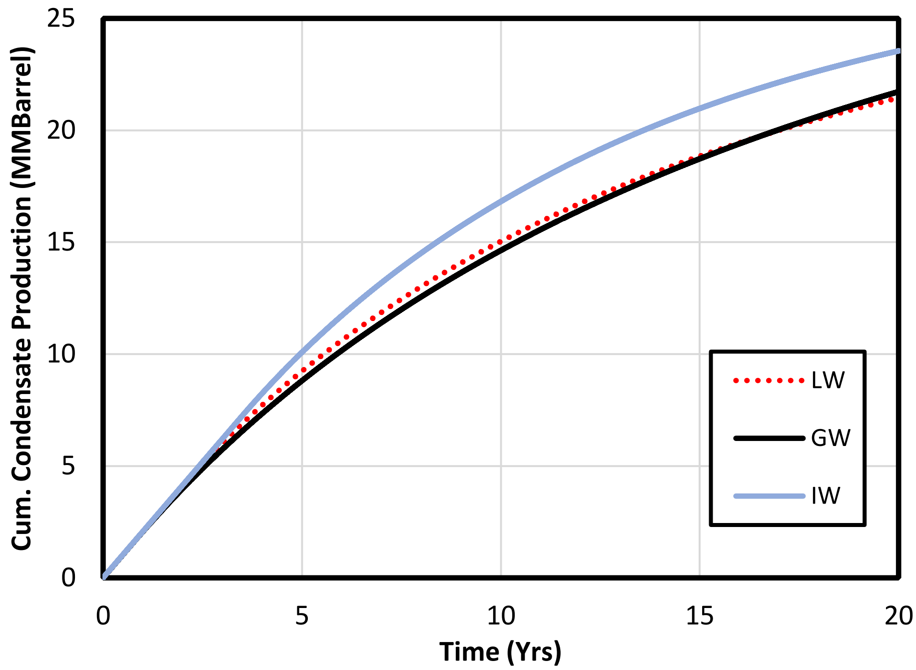


Figure 4-23. Cumulative condensate production from a 15000 ft., 100 md. Reservoir containing Lean fluid

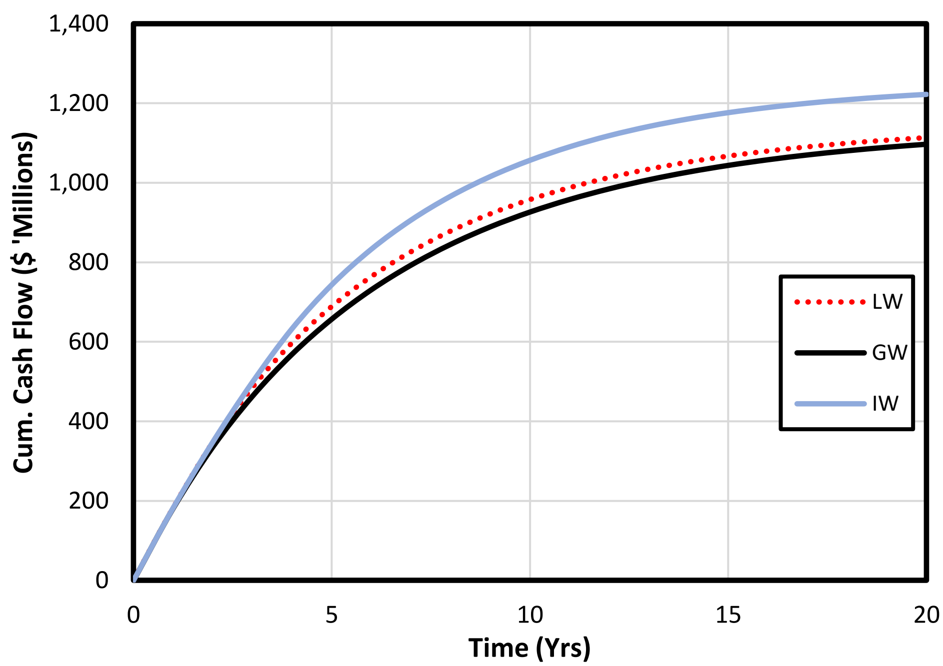


Figure 4-24. Cumulative cash flow from a 15000 ft., 100 md. Reservoir containing Lean fluid

4.2 MEDIUM FLUID.

A consistent observation from the simulation of wettability alteration of a gas reservoir containing medium fluid is that intermediate wetting consistently outperforms gas wetting case. This is consistent with past studies. For a smaller reservoir, wettability alteration does not significantly affect the 20-year cumulative production from the reservoir, but intermediate wetting will likely ensure more production at earlier years. Furthermore, a gas reservoir with a small radius but with large permeability will likely give a discouraging result. Wettability alteration in to preferentially intermediate or gas wetting seems not to have a noticeable impact on well deliverability as established in **section 4.2.1.2** and **Fig. 8-3** and **8-4**

4.2.1 2000-ft reservoir

4.2.1.1 10-md permeability

As indicated in **Fig. 4-25**, in a 2000 ft. reservoir with a permeability of 10 md containing the medium fluid, the gas, and intermediate wetting condition sustained the initial production rate for almost the same length of time but declined sharply to a comparatively lower rate before a steady decline in later years. The BHP change at the GW condition dropped sharply in the first year but approached the minimum BHP at about the same time as the IW condition and later than the LW condition as shown in **Fig. 4-27**. From **Fig 4-26**, it can be observed that, from about the third year, there is a significant difference in the GOR between the three wetting conditions but that at year 20, the GW and IW wetting conditions produced a very close GOR value at the surface. The cumulative production presented in **Fig. 4-28** tells a similar story to the lean case where the final ultimate recovery is the same but earlier rates in the modified wettability cases are higher.

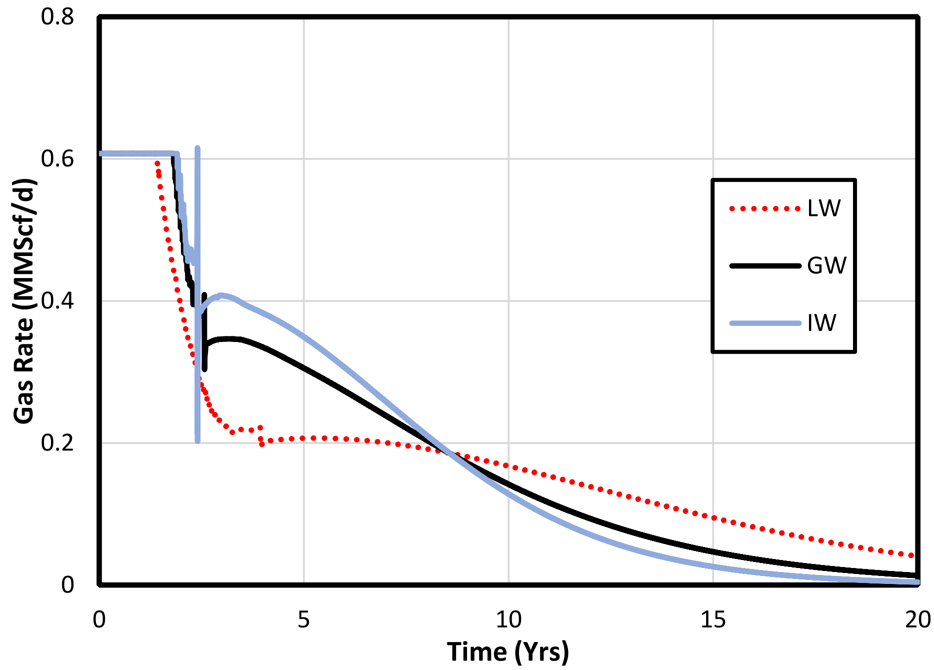


Figure 4-25. Gas Rate from a 2000 ft., 10 md. Reservoir containing Medium fluid

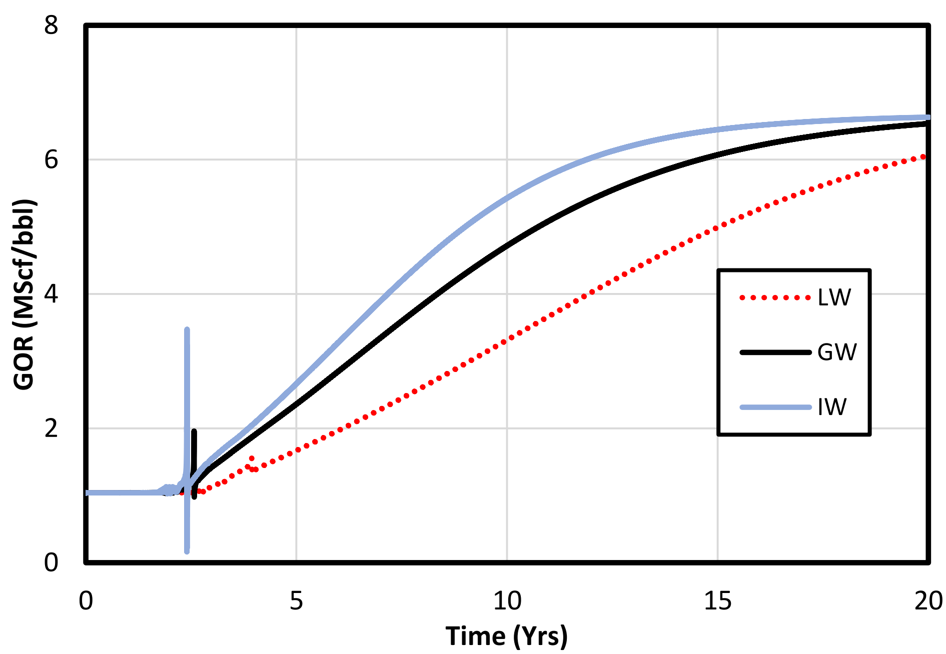


Figure 4-26. GOR from a 2000 ft., 10 md. Reservoir containing Medium fluid

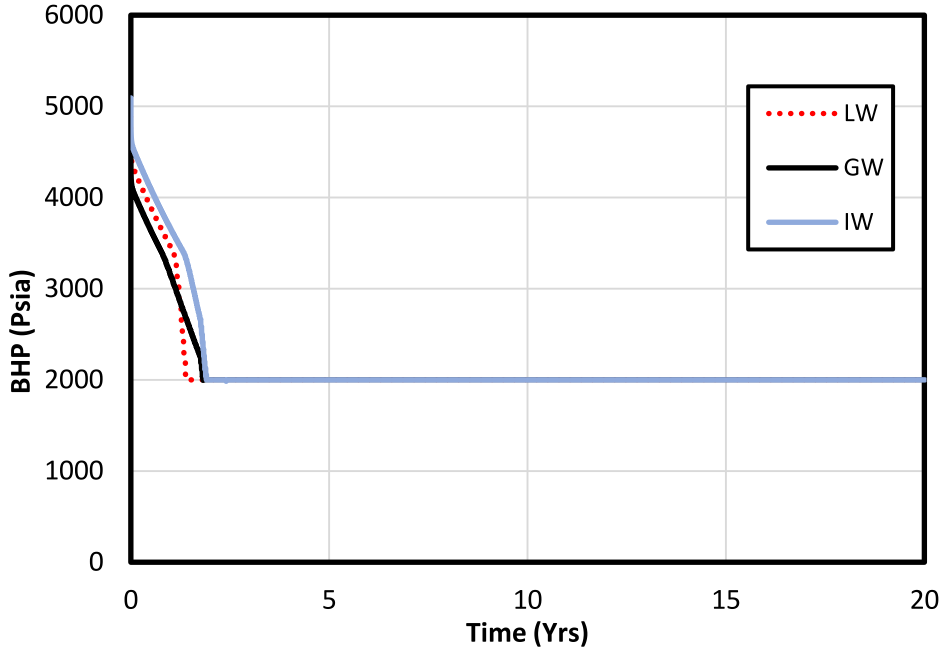


Figure 4-27. BHP from a 2000 ft., 10 md. Reservoir containing Medium fluid

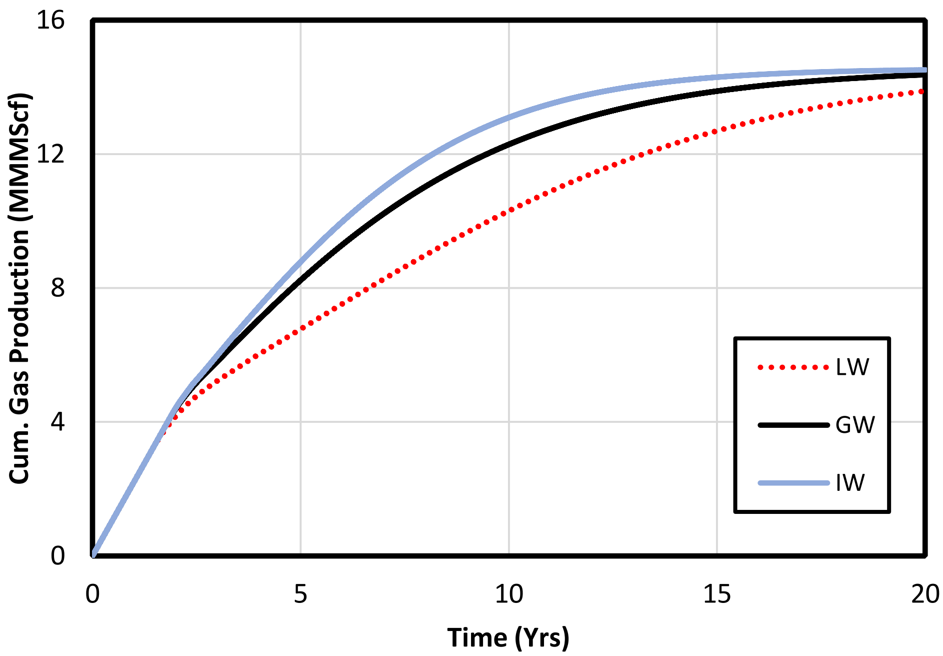


Figure 4-28. Cumulative gas rate from a 2000 ft., 10 md. Reservoir containing Medium fluid

4.2.1.2 100-md Permeability

In a 2000 ft., 100 md reservoir containing medium fluid, **Figs. 4-29**, **30**, **31** and **32** show that the gas rate, BHP, GOR, and cumulative gas production hardly change regardless of the wetting condition for this reservoir and fluid case.

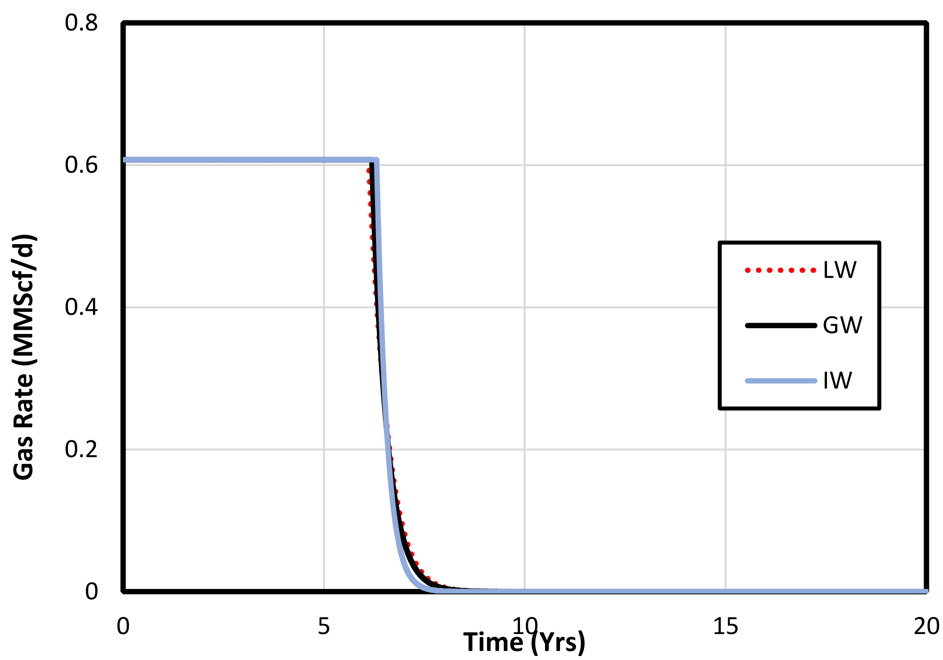


Figure 4-29. Gas Rate from a 2000 ft., 100 md. Reservoir containing Medium fluid

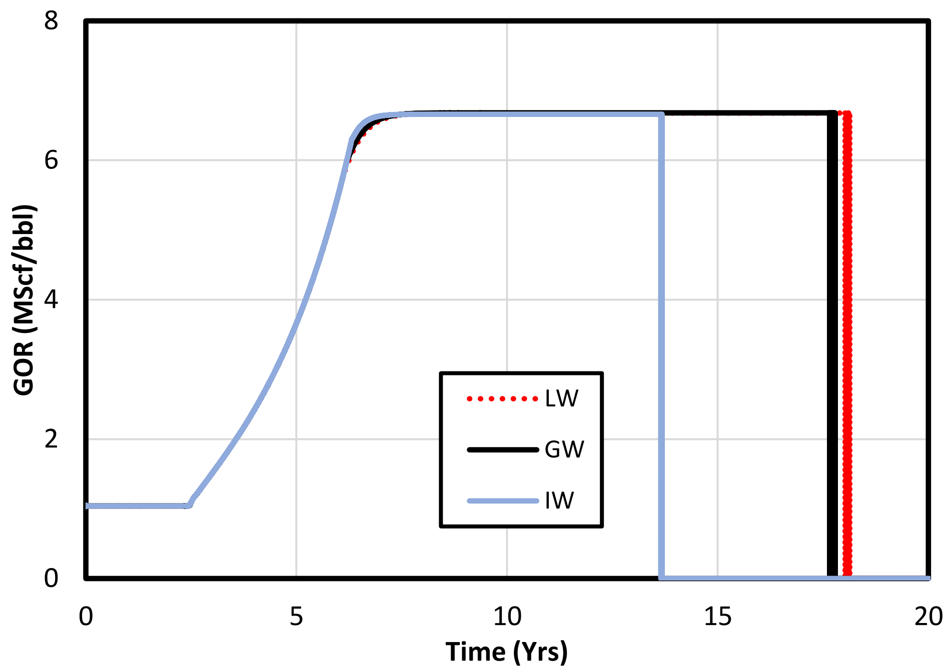


Figure 4-30. GOR from a 2000 ft., 100 md. Reservoir containing Medium fluid

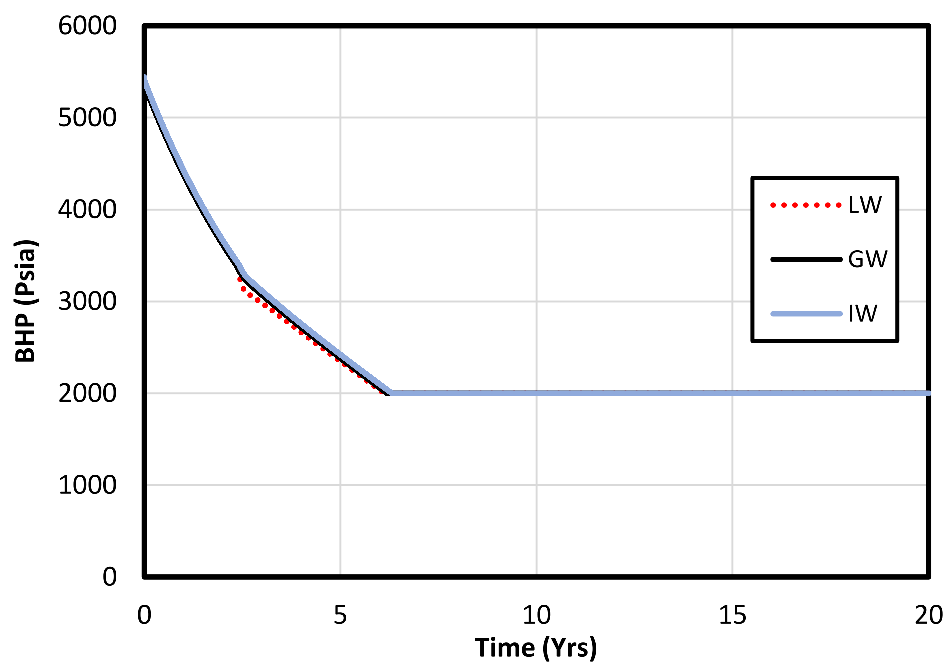


Figure 4-31. BHP from a 2000 ft., 100 md. Reservoir containing Medium fluid

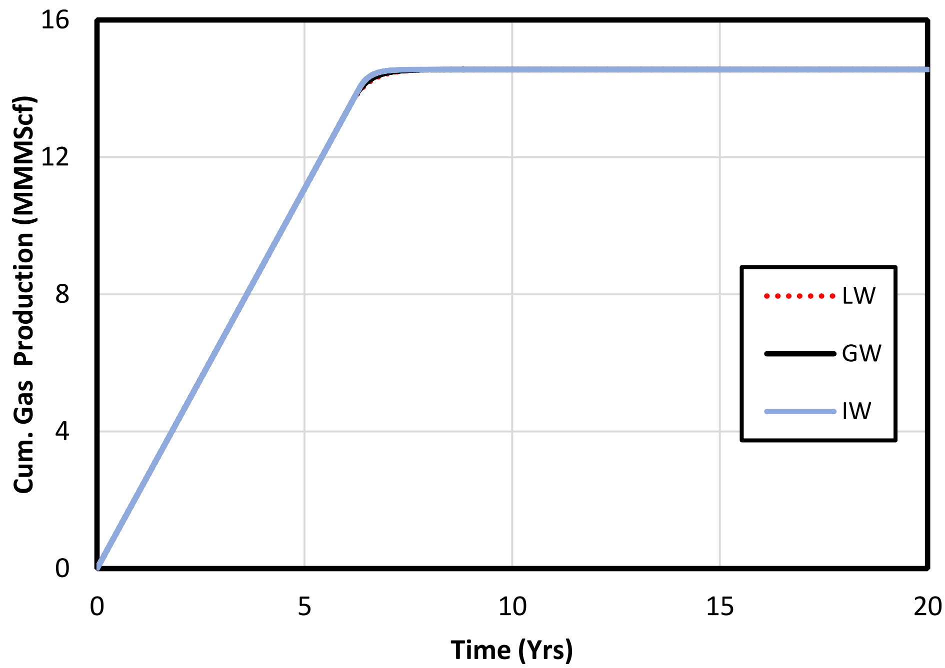


Figure 4-32. Cumulative gas production from a 2000 ft., 100 md. Reservoir containing Medium fluid

4.2.2 15000-ft reservoir

4.2.2.1 10-md permeability

From **Fig 4-33**, it can be observed that in a 15000 ft. reservoir, the IW condition sustained the initial production rate all through the 20-year period, while the gas wetting was only able to sustain the initial production rate for about 7 years before decline sets in. The GOR as indicated in **Fig. 34**, did not change all through the years for the three wetting conditions. The intermediate wetting clearly improves the gas and liquid mobility from the reservoir and evident in the improved 20-year cumulative gas and condensate production in **Fig. 4-36** and **8-3** respectively.

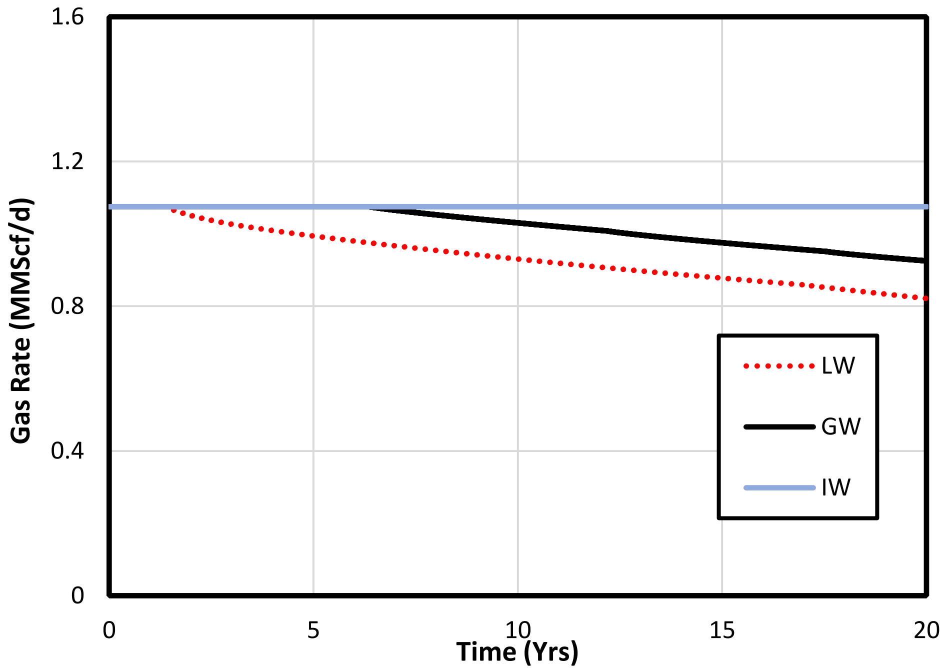


Figure 4-33. Gas Rate from a 15000 ft., 10 md. Reservoir containing Medium fluid

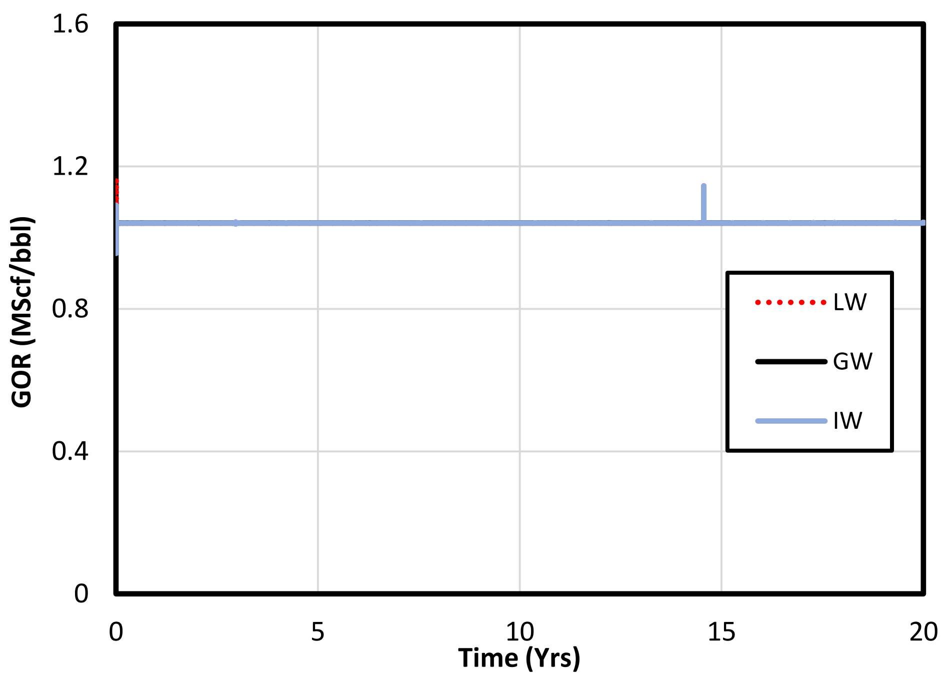


Figure 4-34. GOR from a 15000 ft., 10 md. Reservoir containing Medium fluid

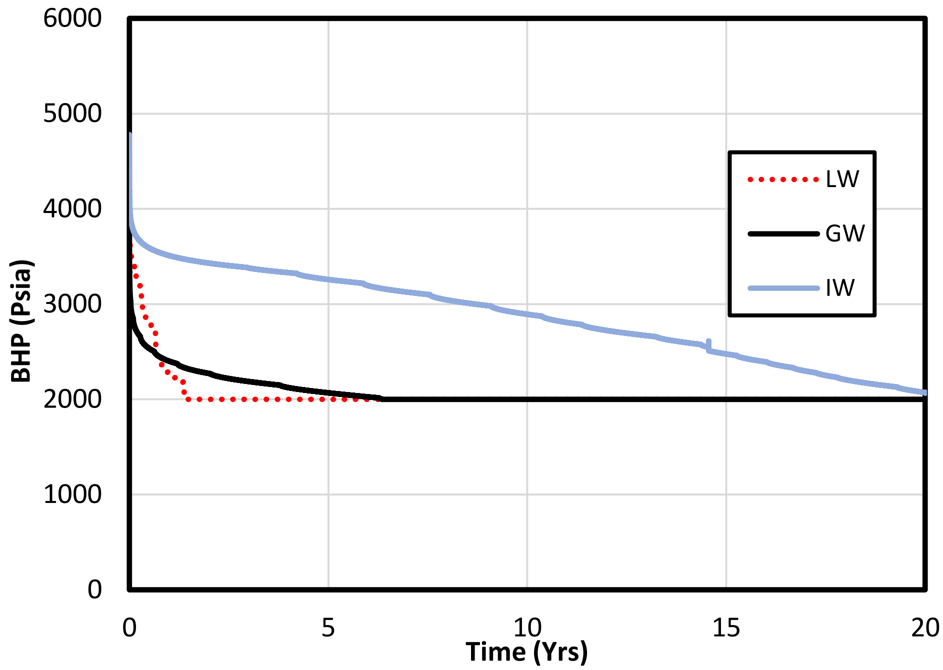


Figure 4-35. BHP from a 15000 ft., 10 md. Reservoir containing Medium fluid

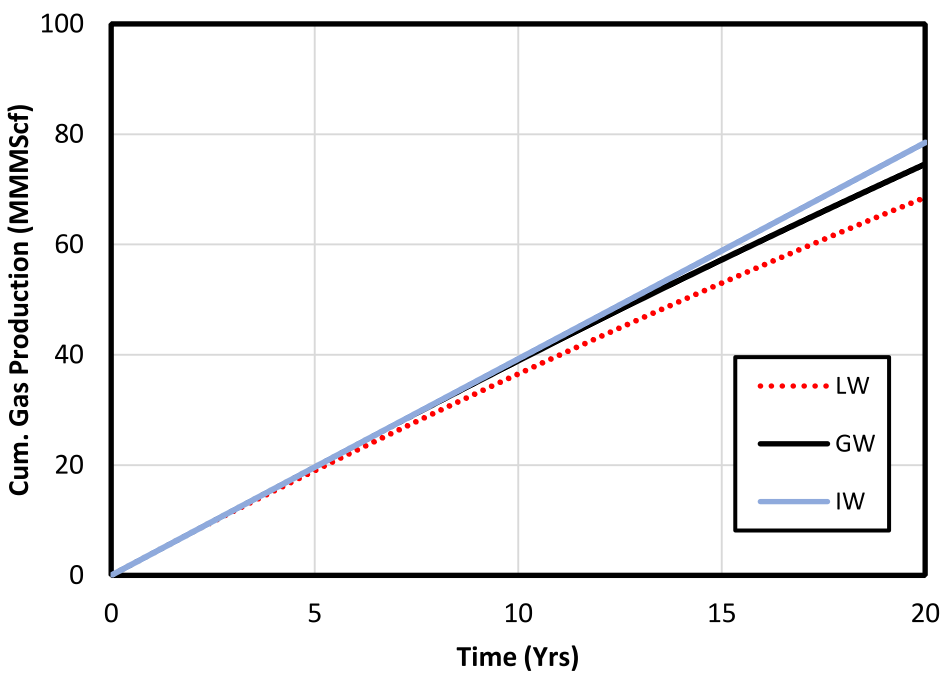


Figure 4-36. Cumulative production from a 15000 ft., 10 md. Reservoir containing Medium fluid

4.2.2.2 100-md permeability

From **Fig 4-37**, it can be observed that in a 15000 ft. radius reservoir, gas, and intermediate wetting sustained the initial production rate longer than the liquid wetting condition. The IW condition proves to be the best option in this reservoir and fluid condition as it maintains a slightly higher flow rate than GW all through the production years. The GOR for the three wetting conditions remains fairly flat, with a slight increase in GOR in the later years for GW and IW conditions. In addition, wettability alteration clearly enhanced the well productivity as established in **Fig. 4-40** and **Fig. 8-8** showing improved 20-year cumulative gas and condensate production respectively with intermediate wetting being the better option relative to gas wetting.

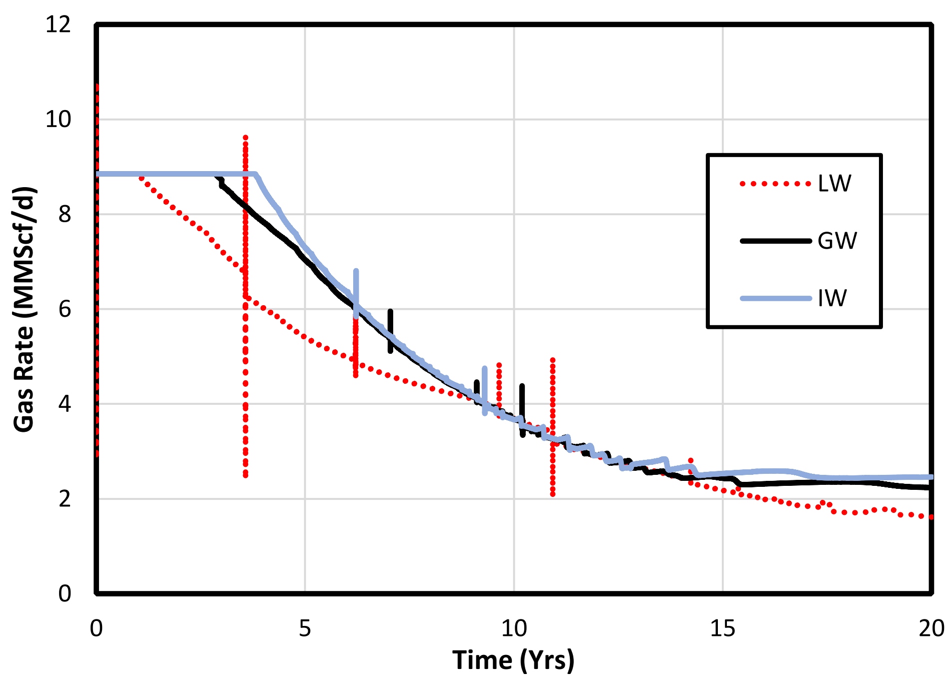


Figure 4-37. Gas Rate from a 15000 ft., 100 md. Reservoir containing Medium fluid

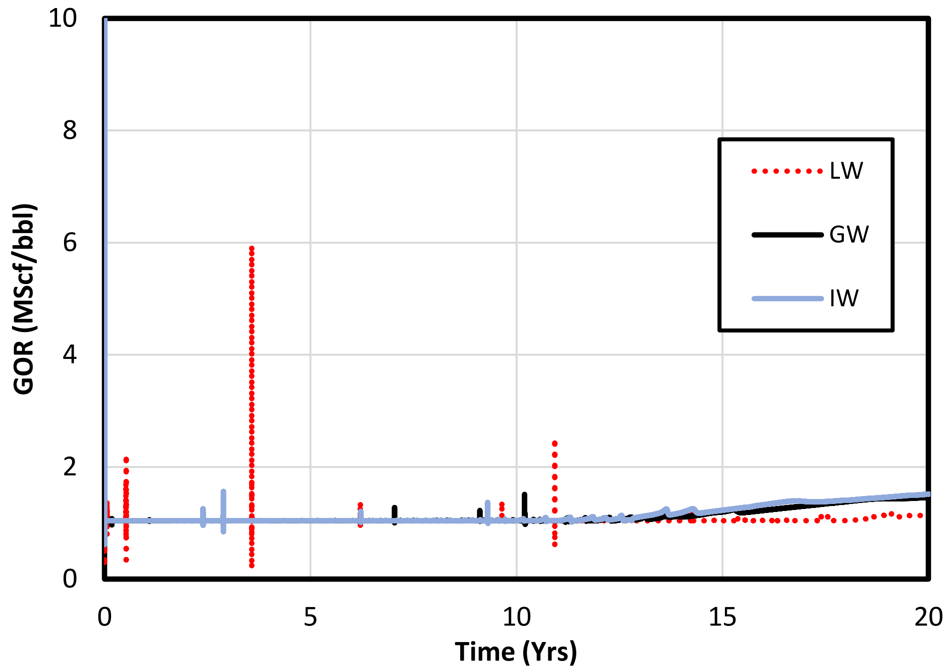


Figure 4-38. GOR from a 15000 ft., 100 md. Reservoir containing Medium fluid

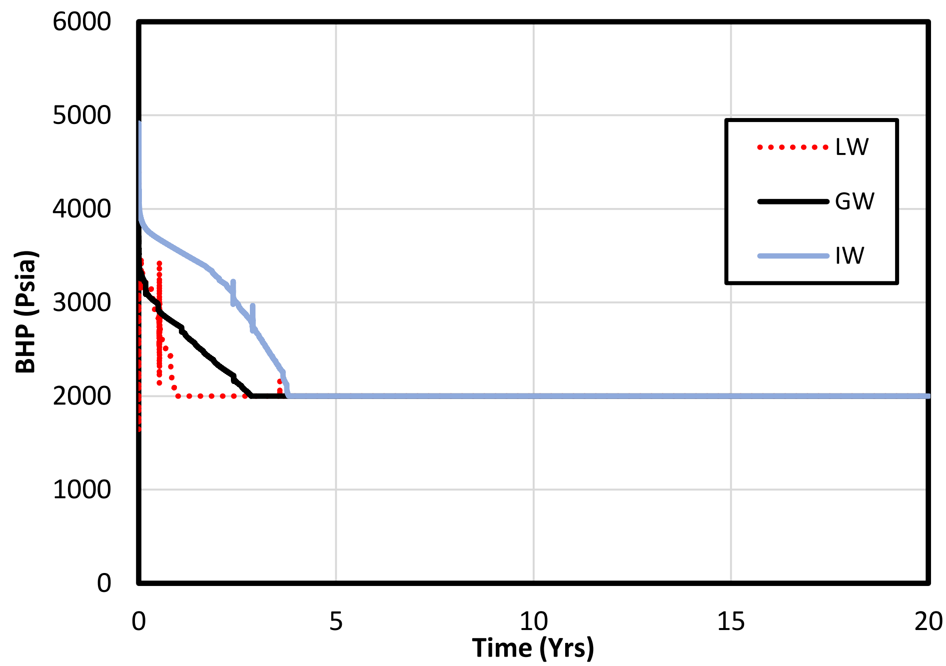


Figure 4-39. BHP from a 15000 ft., 100 md. Reservoir containing Medium fluid

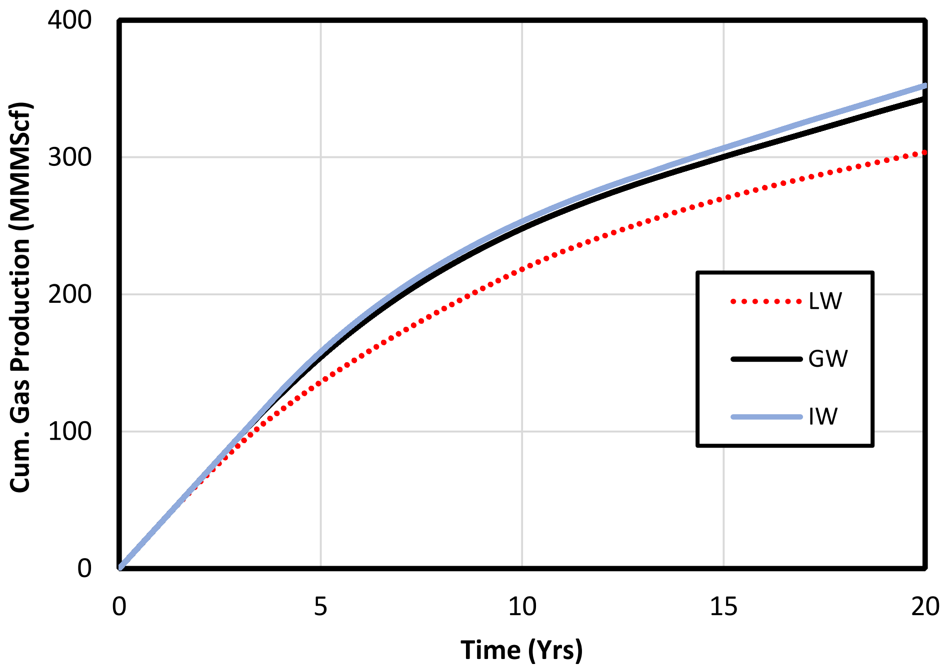


Figure 4-40. Cumulative gas rate from a 15000 ft., 100 md. Reservoir containing Medium fluid

4.3 RICH FLUID.

The observation from the simulation of wettability alteration for a rich gas reservoir is very much consistent with trends from wettability alteration of the lean gas reservoir and medium gas reservoir. Wettability alteration of a small reservoir with large permeability does not improve the well deliverability in this case likewise as established in **Fig. 4-44** and **Fig 8-11**. In other cases, GW and IW definitely improve the liquid and condensate mobility but the IW condition was consistently a better wetting option relative to GW.

4.3.1 2000-ft reservoir

4.3.1.1 10-md permeability

As indicated in **Fig. 4-25**, in a 2000 ft. reservoir with a permeability of 10 md containing the medium fluid, the gas, and intermediate wetting condition sustained the initial production rate for almost the same length of time but declined sharply to a comparatively lower rate before a steady decline in later years. The BHP change at the LW condition dropped sharply in the first year but the gas and intermediate wetting dropped fairly later with the IW reaching the minimum bottom hole pressure much later as shown in **Fig. 4-43**. From **Fig 4-42** shows that for a rich gas reservoir, there is an increase in the GOR from the first year of production regardless of the wettability of the reservoir. The GOR for IW increases at a much faster rate than LW and GW but the GOR at the end of 20-year production of the well was the same for the of the three wetting options. The cumulative production presented in **Fig. 4-44 and Fig 8-9** tells a similar story to the lean and medium case where the final ultimate recovery is somewhat the same but gas and condensate rates in the earlier years for the modified wettability cases are higher.

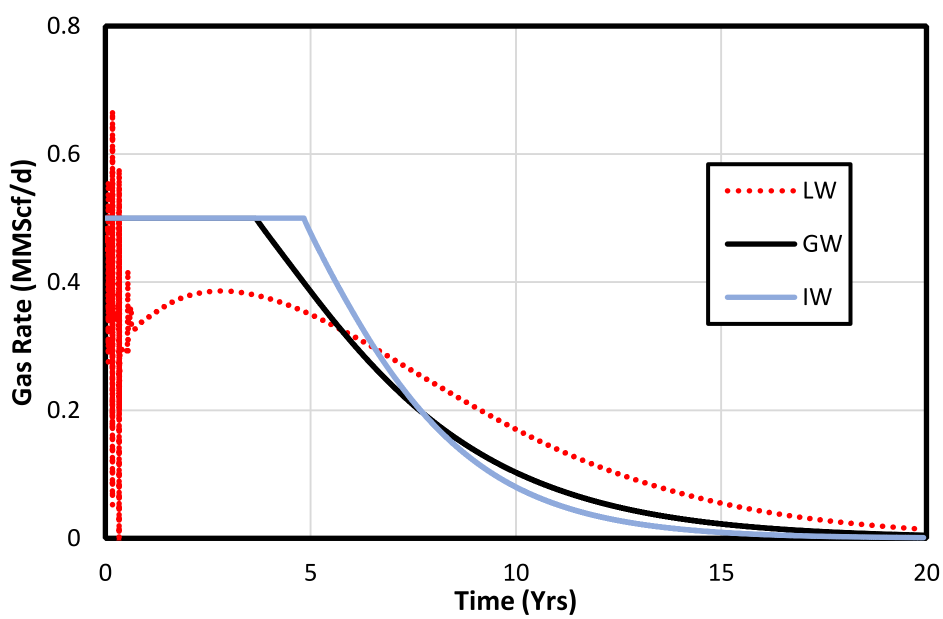


Figure 4-41. Gas Rate from a 2000 ft., 10 md. Reservoir containing Rich fluid

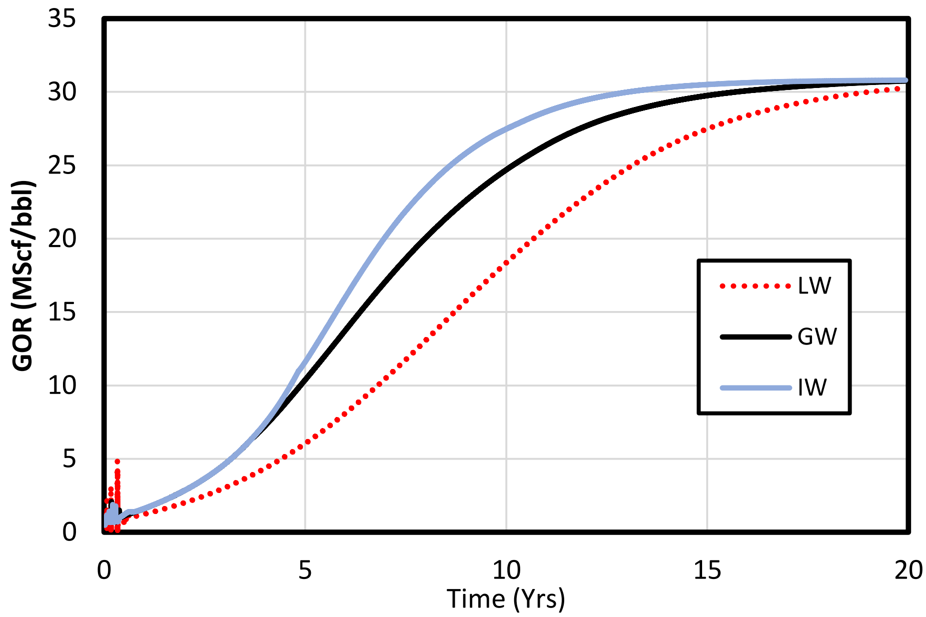


Figure 4-42. GOR from a 2000 ft., 10 md. Reservoir containing Rich fluid

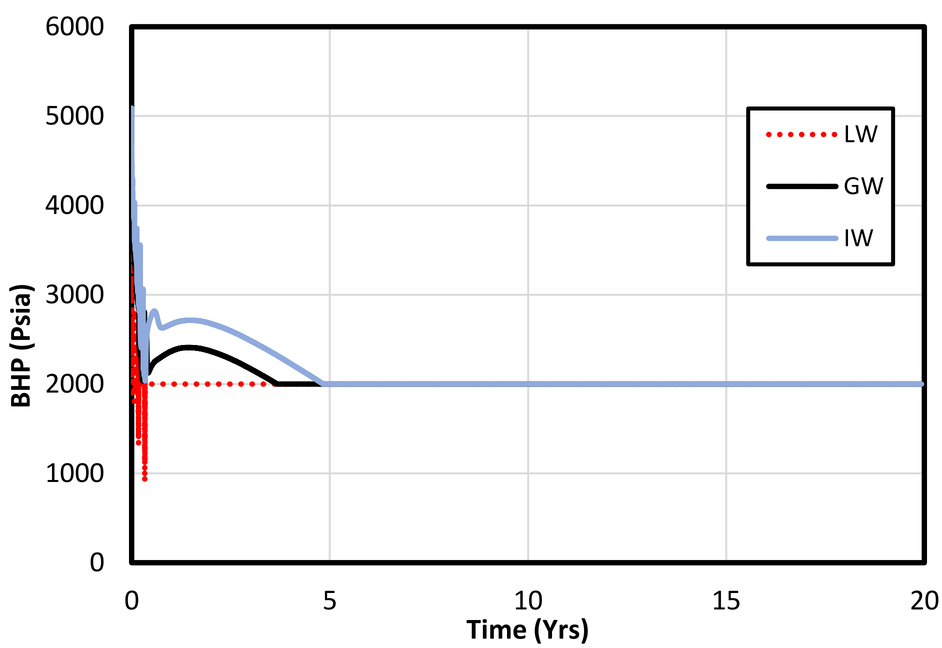


Figure 4-43. BHP from a 2000 ft., 10 md. Reservoir containing Rich fluid

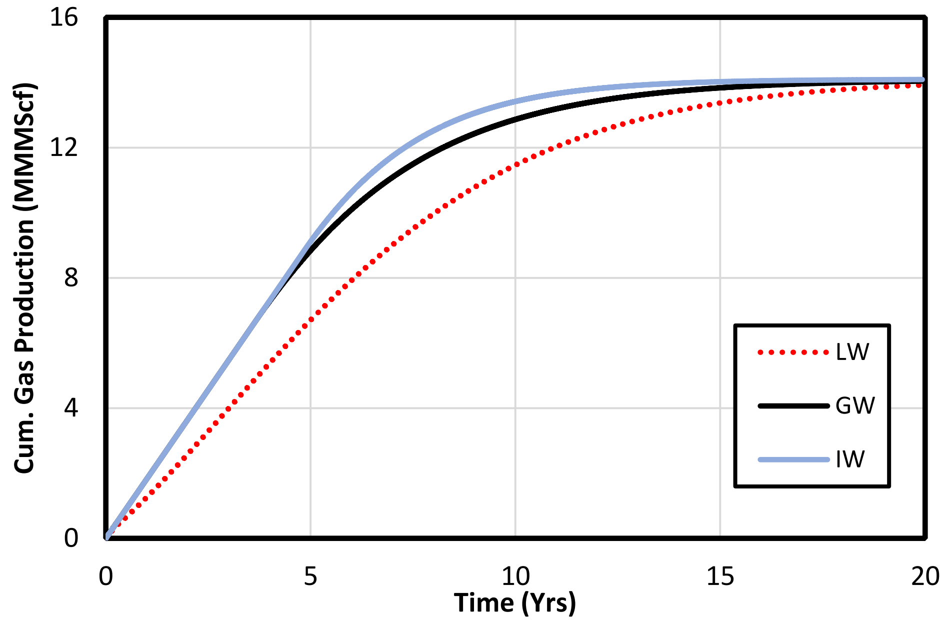


Figure 4-44. Cumulative gas rate from a 2000 ft., 10 md. Reservoir containing Rich fluid

4.3.1.2 100-md Permeability

In a 2000 ft., 100 md reservoir containing rich fluid, **Figs. 4-46**, **4-30**, **4-31** and **4-32** show that the gas rate, BHP, GOR, and cumulative gas production does not change regardless of the wetting condition for this reservoir and fluid case. This observation is consistent with the case of lean and medium fluid in a gas reservoir of similar size and permeability.

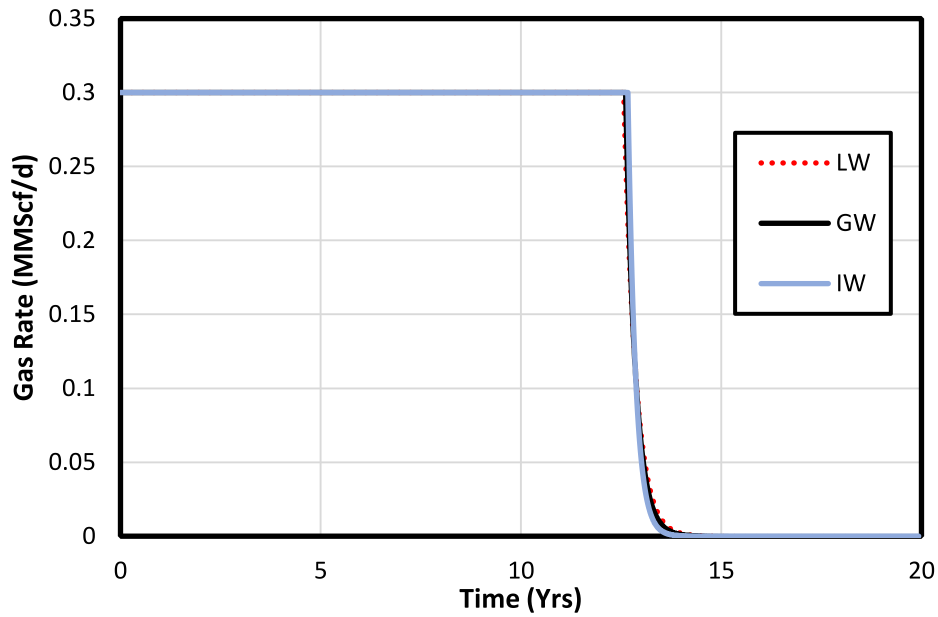


Figure 4-45. Gas Rate from a 2000 ft., 100 md. Reservoir containing Rich fluid

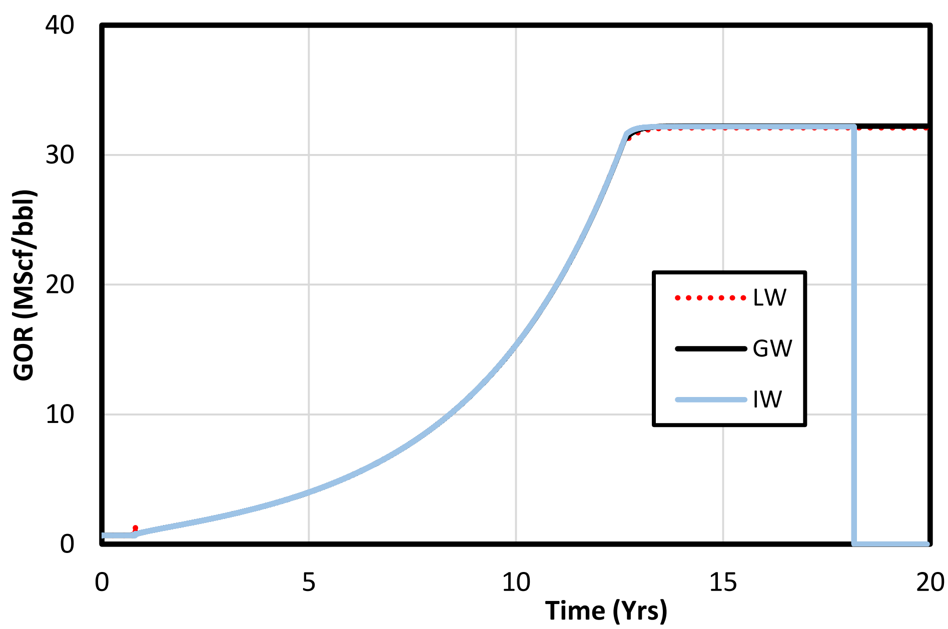


Figure 4-46. GOR from a 2000 ft., 100 md. Reservoir containing Rich fluid

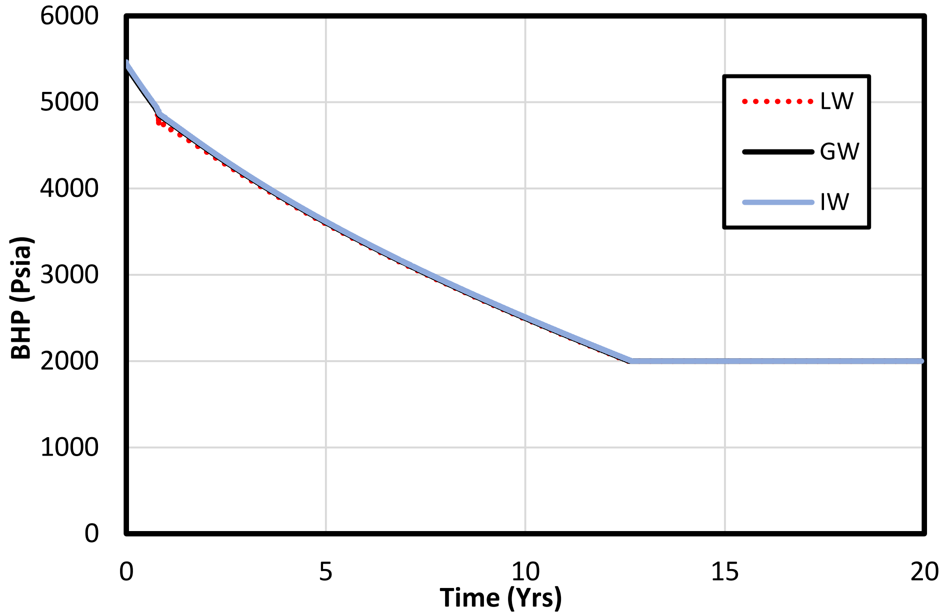


Figure 4-47. BHP from a 2000 ft., 100 md. Reservoir containing Rich fluid

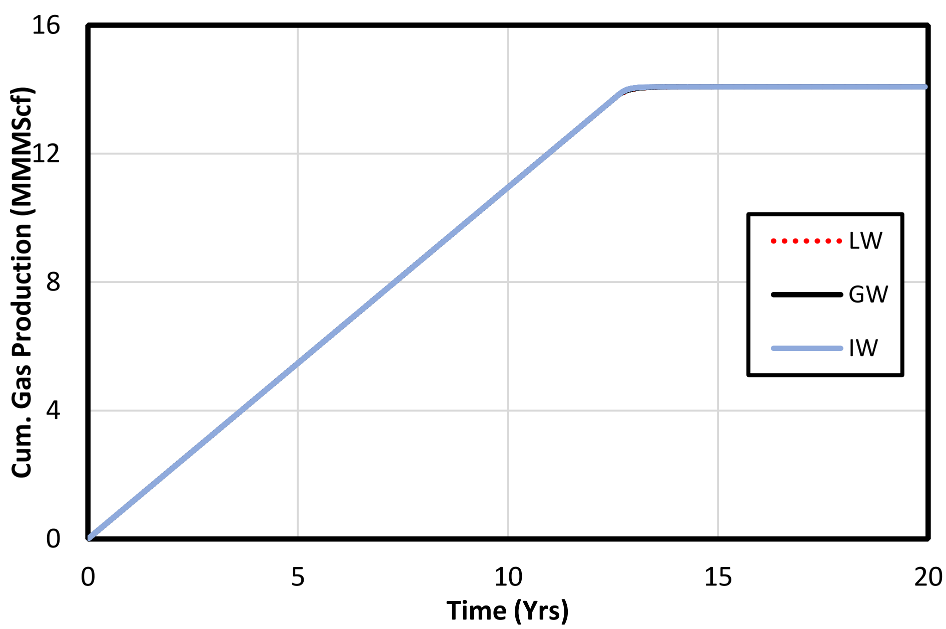


Figure 4-48. Cumulative gas production from a 2000 ft., 100 md. Reservoir containing Rich fluid

4.3.2 15000-ft reservoir

4.3.2.1 10-md permeability

From **Fig 4-49**, it can be seen that in a 15000 ft. reservoir, the IW condition sustained the initial production rate the longest compared to the other two wettability options. When the well was produced at the default liquid wetting condition, a sharp drop in production was encountered, while the gas wetting was only able to sustain the initial production rate for about few years before decline sets in. The GOR as indicated in **Fig. 4-50**, did not change all through the years for the three wetting conditions. The intermediate wetting clearly improves the gas and liquid mobility from the reservoir, and it is evident in the improved 20-year cumulative gas and condensate production in **Fig. 4-51** and **8.13** respectively.

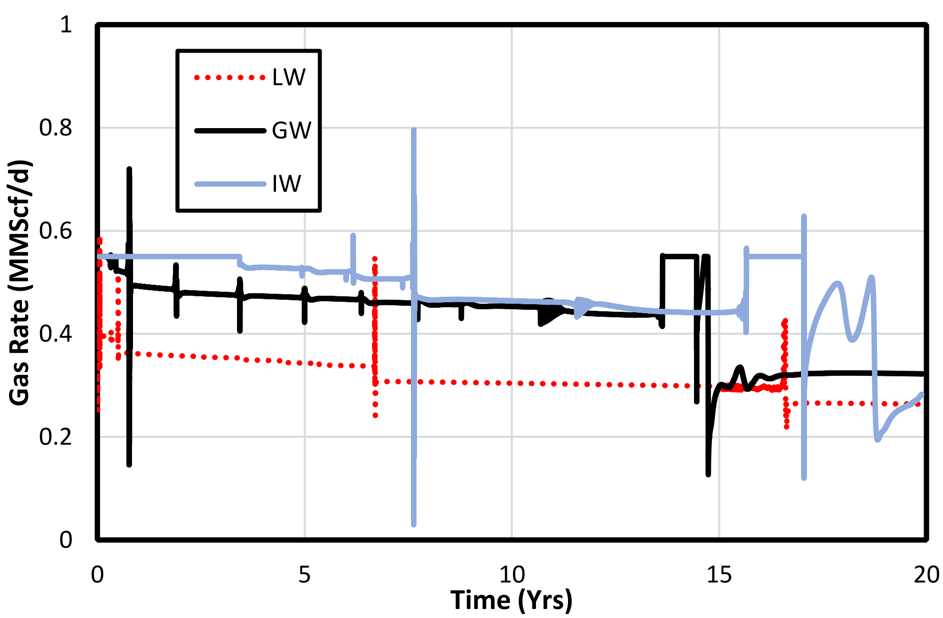


Figure 4-49. Gas Rate from a 15000 ft., 10 md. Reservoir containing Rich fluid

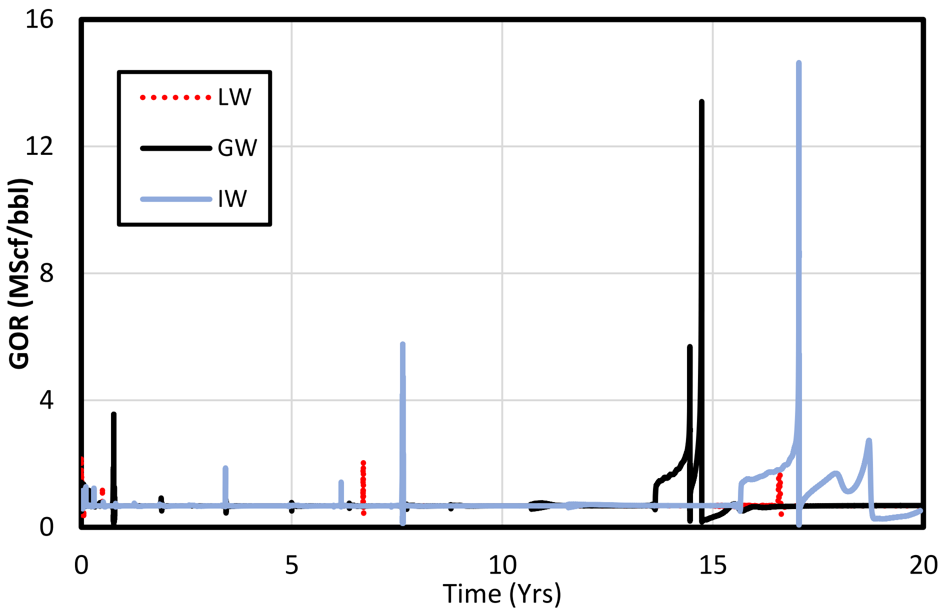


Figure 4-50. GOR from a 15000 ft., 10 md. Reservoir containing Rich fluid

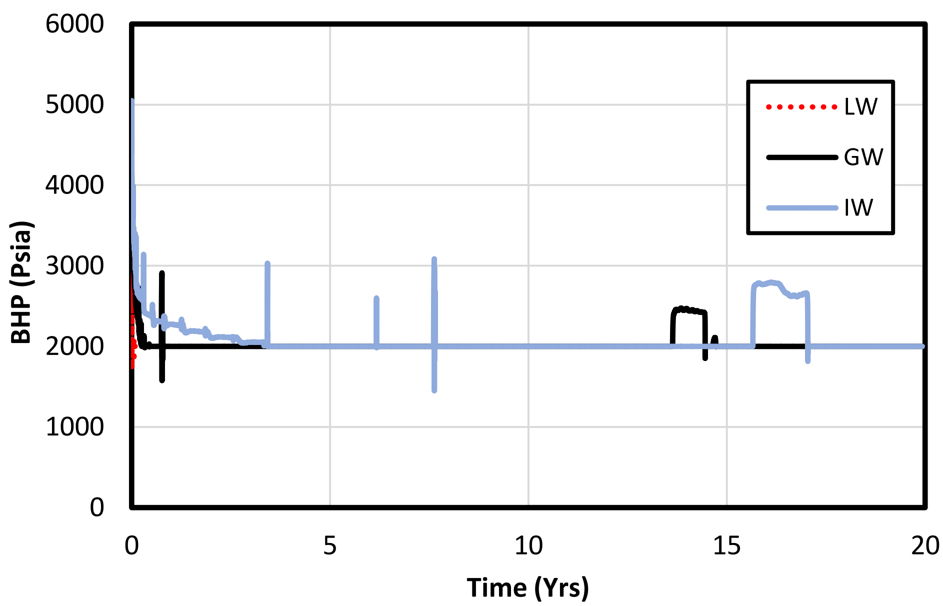


Figure 4-51. BHP from a 15000 ft., 10 md. Reservoir containing Rich fluid

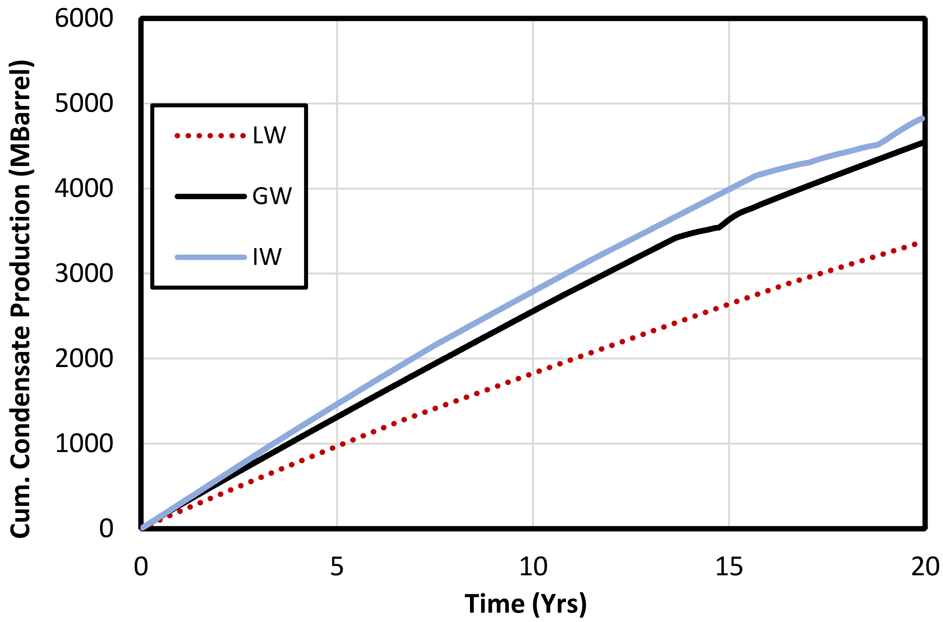


Figure 4-52. Cumulative production from a 15000 ft., 10 md. Reservoir containing Rich fluid

4.3.2.2 100-md permeability

Fig 4-53 shows that in a 15000 ft. radius reservoir containing rich fluid, gas and intermediate wetting sustained the initial production rate longer than the liquid wetting condition. The IW condition proves to be the best option in this reservoir and fluid condition as it maintains a slightly higher flow rate than GW all through the production years. The GOR for the three wetting conditions remains fairly flat through the 20-year production period. In addition, wettability alteration clearly enhanced the well productivity as established in **Fig. 4-56** and **Fig. 8-16** showing improved 20-year cumulative gas and condensate production respectively with intermediate wetting being the better option relative to gas wetting as expected.

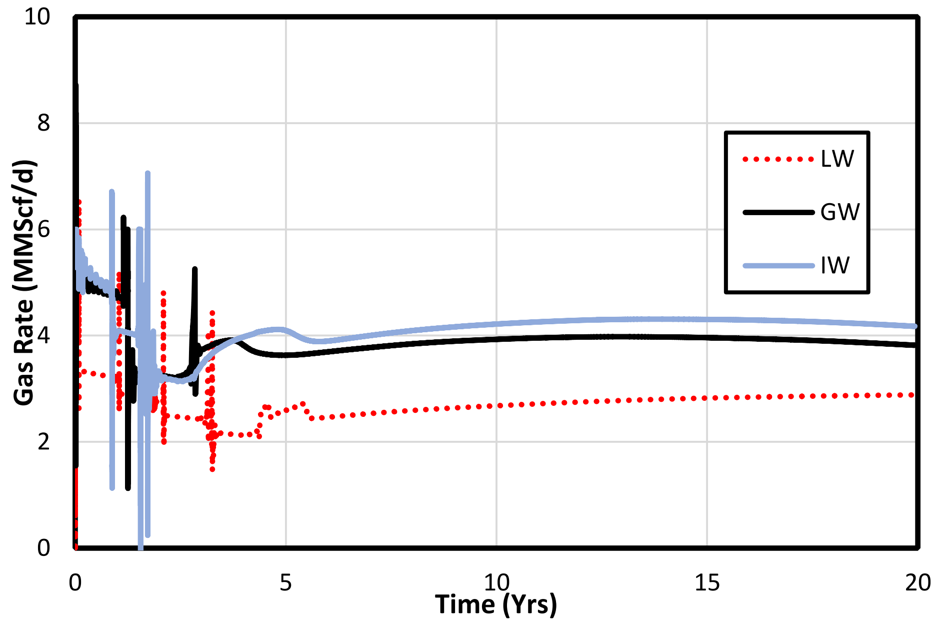


Figure 4-53. Gas Rate from a 15000 ft., 100 md. Reservoir containing Rich fluid

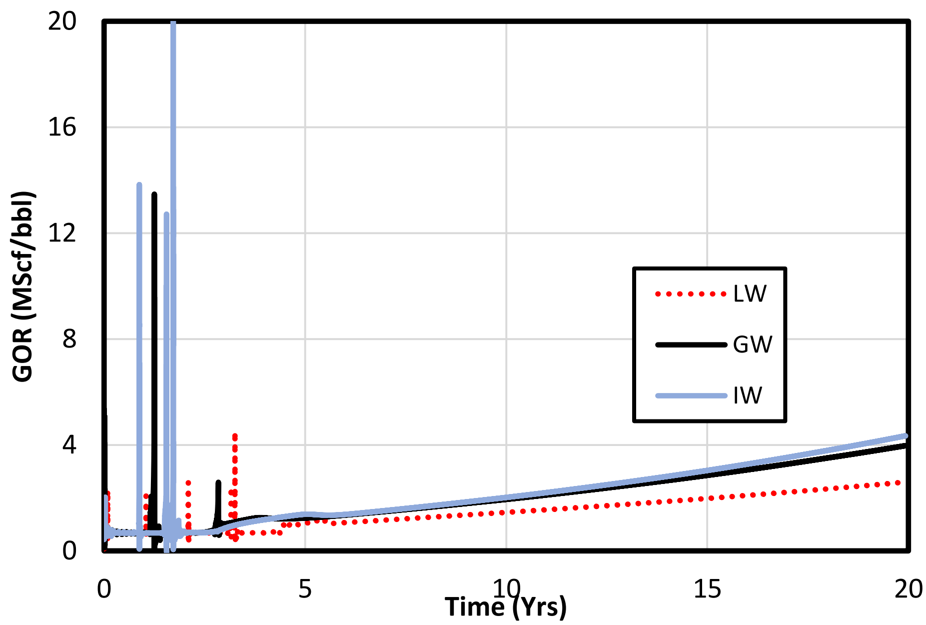


Figure 4-54. GOR from a 15000 ft., 100 md. Reservoir containing Rich fluid

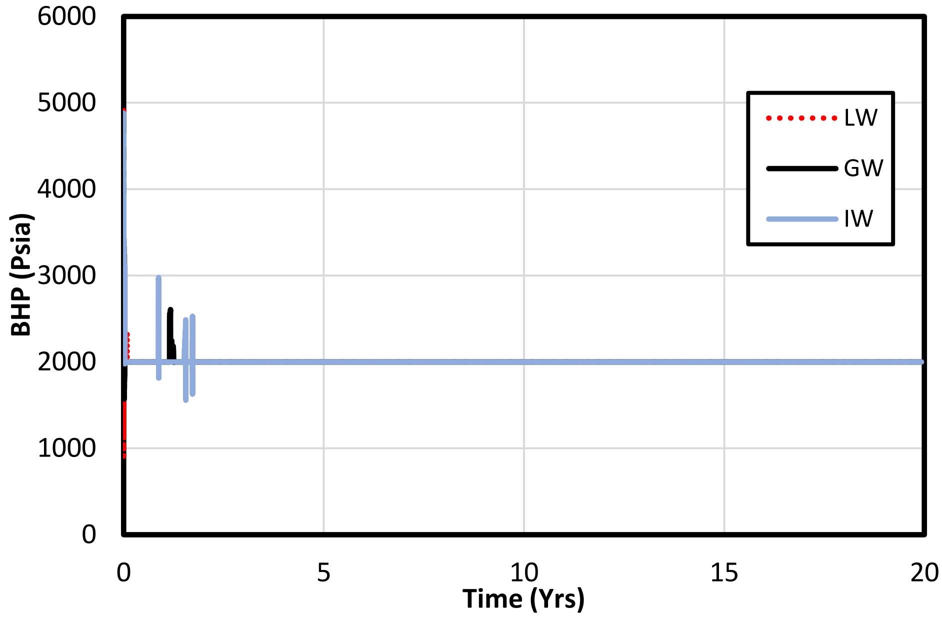


Figure 4-55. BHP from a 15000 ft., 100 md. Reservoir containing Rich fluid

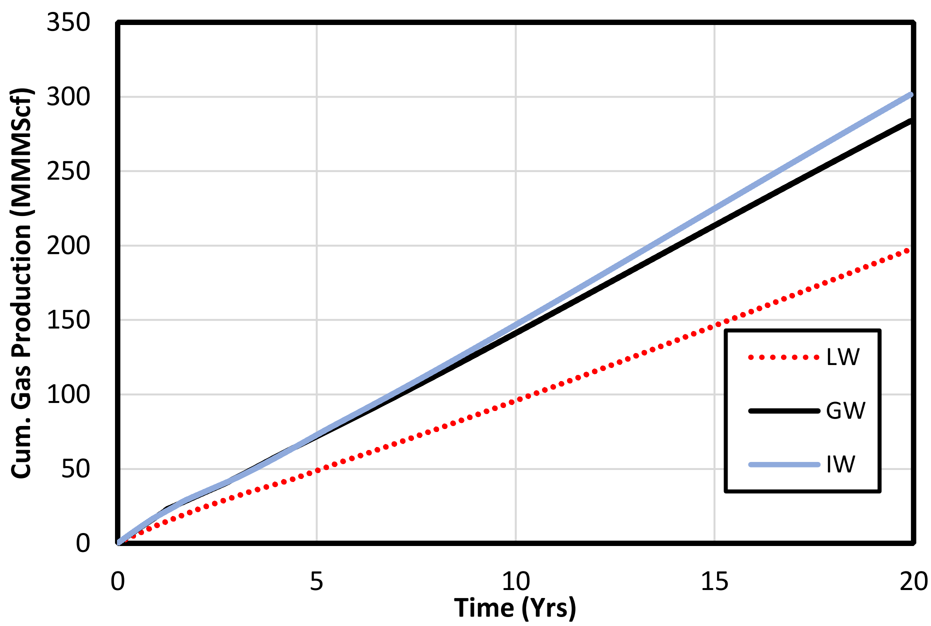


Figure 4-56. Cumulative gas rate from a 15000 ft., 100 md. Reservoir containing Rich fluid

4.4. EFFECT OF RESERVOIR PERMEABILITY ON WETTABILITY ALTERATION.

To study the effect of reservoir radius and reservoir size, we considered medium fluid and intermediate wetting only. Production across four reservoir sizes – 2,000 ft., 5,000 ft., 10,000 ft., and 15,000 ft.; were modeled considering for reservoir permeability values – 10 md, 30 md, 70 md, and 100 md.

Figure 4-57 captures how the performance of wettability alteration varies with different permeability and reservoir sizes. At a reservoir size of 2000-ft, if the permeability of the reservoir is higher than 20 md, wettability alteration will not improve well deliverability from such reservoir. With reservoir draining from a larger radius, the effect of permeability becomes less of a problem. **Figure 4-57** shows that wettability alteration could effectively enhance the production from the gas reservoir with permeability up to 60 md while gas condensate reservoir of size greater than 10,000 ft. would be a good candidate from wettability alteration treatment regardless of it permeability

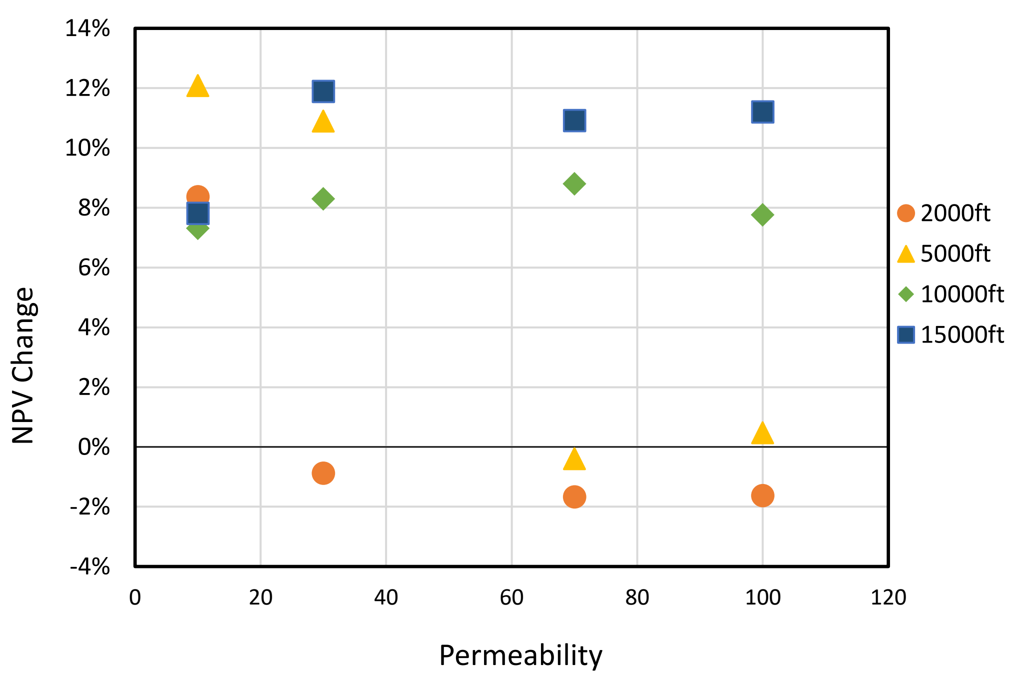


Figure 4-57. Performance of wettability alteration for reservoirs of various drainage radius by wetting type

4.5 SUMMARY OF WETTABILITY ALTERATION.

This section presents the summary of the wettability alteration from our simulation models. The results are presented in 2 modes – as a function of the treatment type and as a function of the fluid type.

4.5.1 Evaluation of wettability alteration in 2000-ft reservoir

Figure 4-58 presents the results for wettability alteration for 2000-ft gas condensate reservoir. Three observations stand out from **Fig. 4-58**. Intermediate wetting is a better treatment option and a large permeability gas condensate reservoir with 2000-ft drainage radius will perform poorly to any form of wettability treatment. In addition, the more the heavy components (i.e. C7+) the reservoir fluid contains, the more suitable the reservoir is for wettability alteration treatment. Interestingly, the medium fluid appears to be the best fluid composition amongst the three considered as established in **figure 4-58**. The medium fluid consistently outperforms rich fluid regardless of the wettability treatment type. Hence, for a reservoir with drainage radius of about 2000-ft, low permeability and fluid with condensate yield in the range of a medium fluid (~ 96 bbl/MMScf) would be an ideal reservoir and fluid condition for optimal performance of use of wettability alteration to enhance well deliverability.

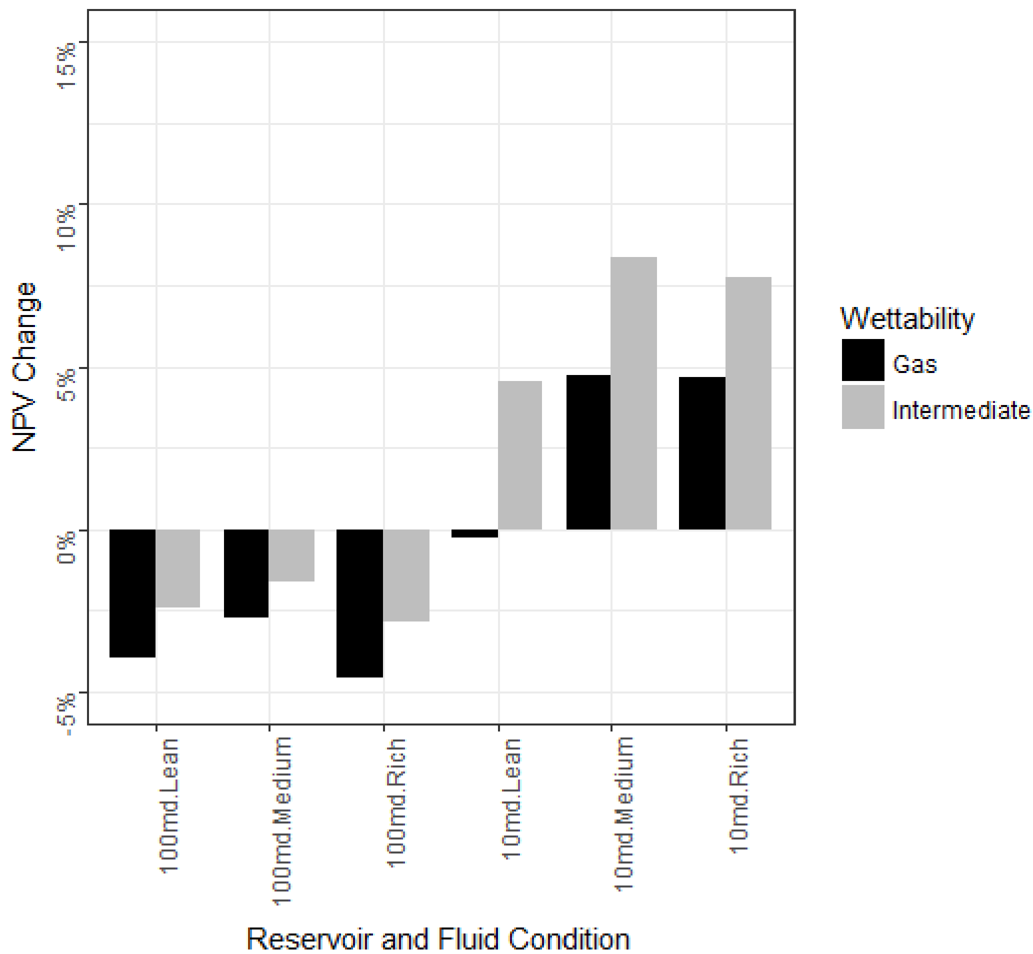


Figure 4-58: performance of wettability alteration for 2000-ft reservoir by wetting type

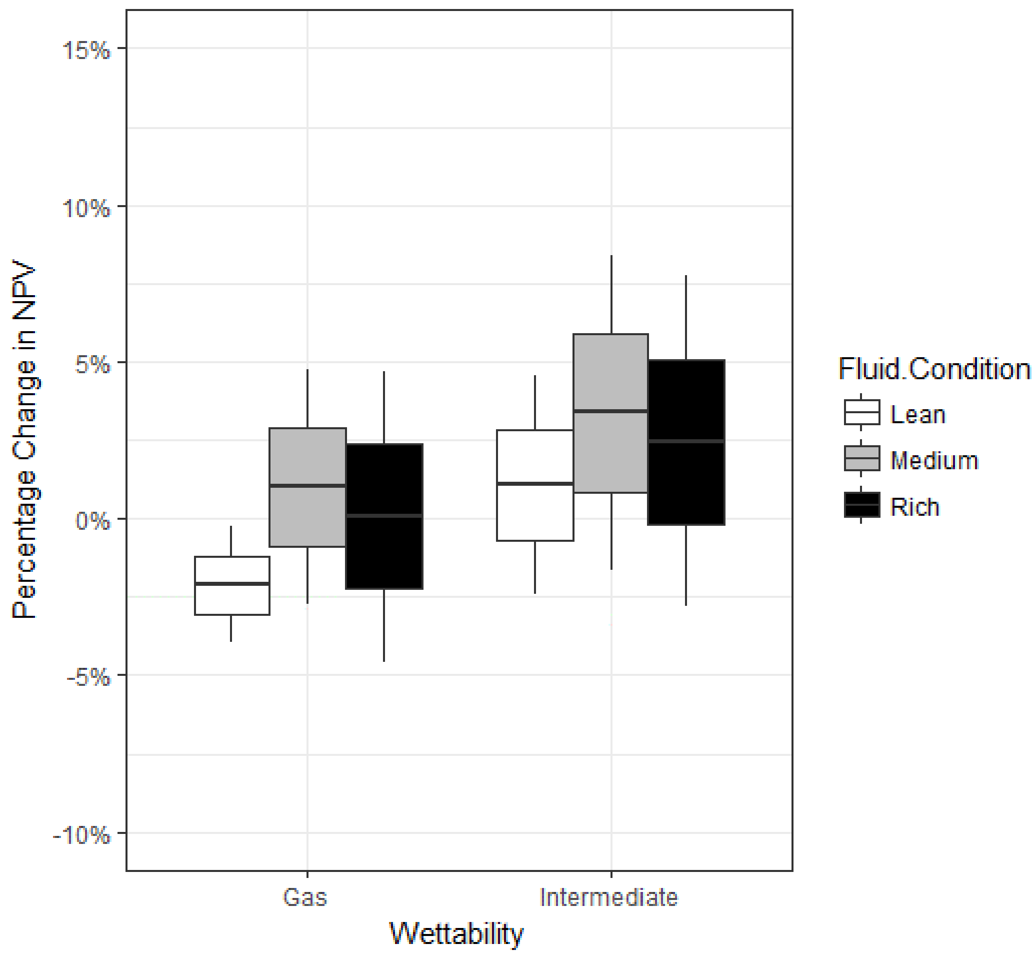


Figure 4-59: performance of wettability alteration treatment for 2000-ft reservoir by fluid type

4.5.2 Evaluation of wettability alteration in 15000-ft reservoir

Some of the key takeaways from wettability alteration of a giant reservoir with drainage radius of 15000 ft. are consistent with that of a small reservoir in **section 4.5.1**. Intermediate wetting remains the better treatment option and lean fluid still has the least improvement in post-treatment well deliverability. However, the large reservoir drainage radius makes the wettability alteration treatment resilient to the effect of permeability, because, even at high permeability, the wettability alteration enhanced gas and condensation production from the well as established in **Fig. 4-60**. In addition, **Fig. 4-61** shows that a reservoir with rich gas will give the best post wettability treatment result when the reservoir drains for a large drainage area.

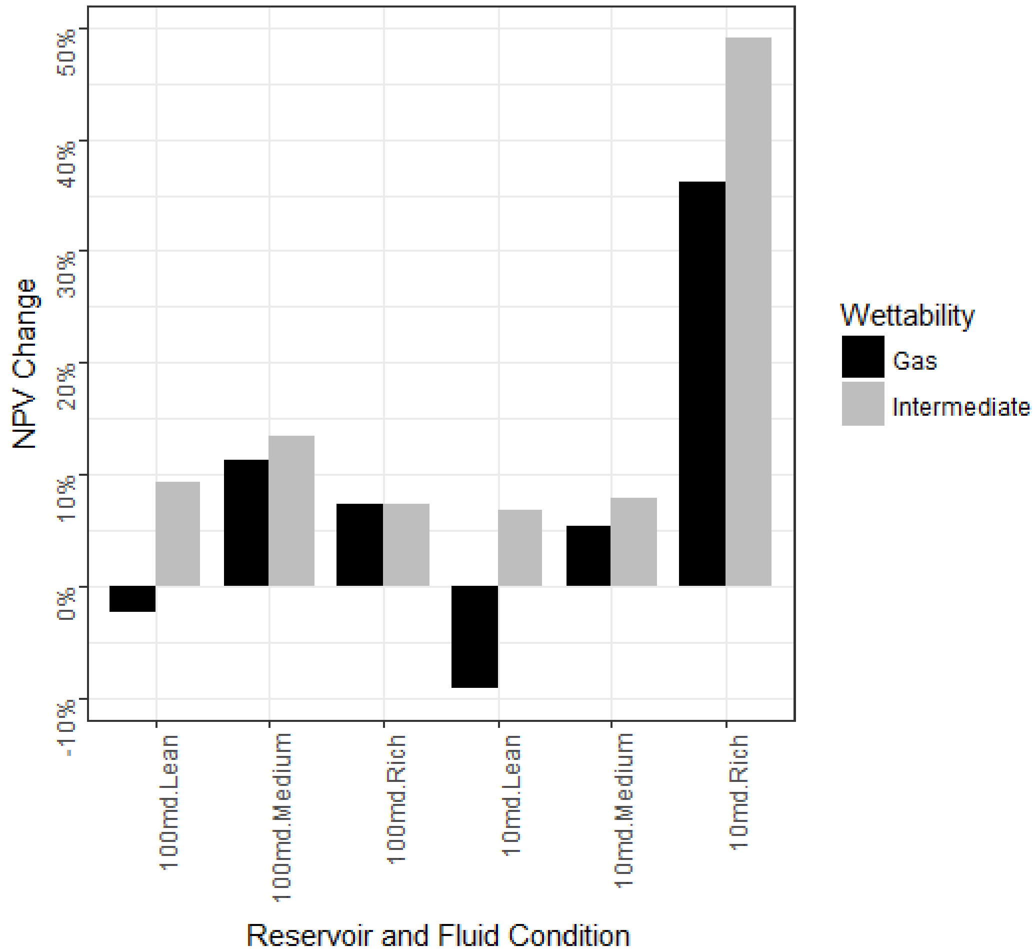


Figure 4-60: summary of wettability alteration for 15000-ft reservoir by treatment type

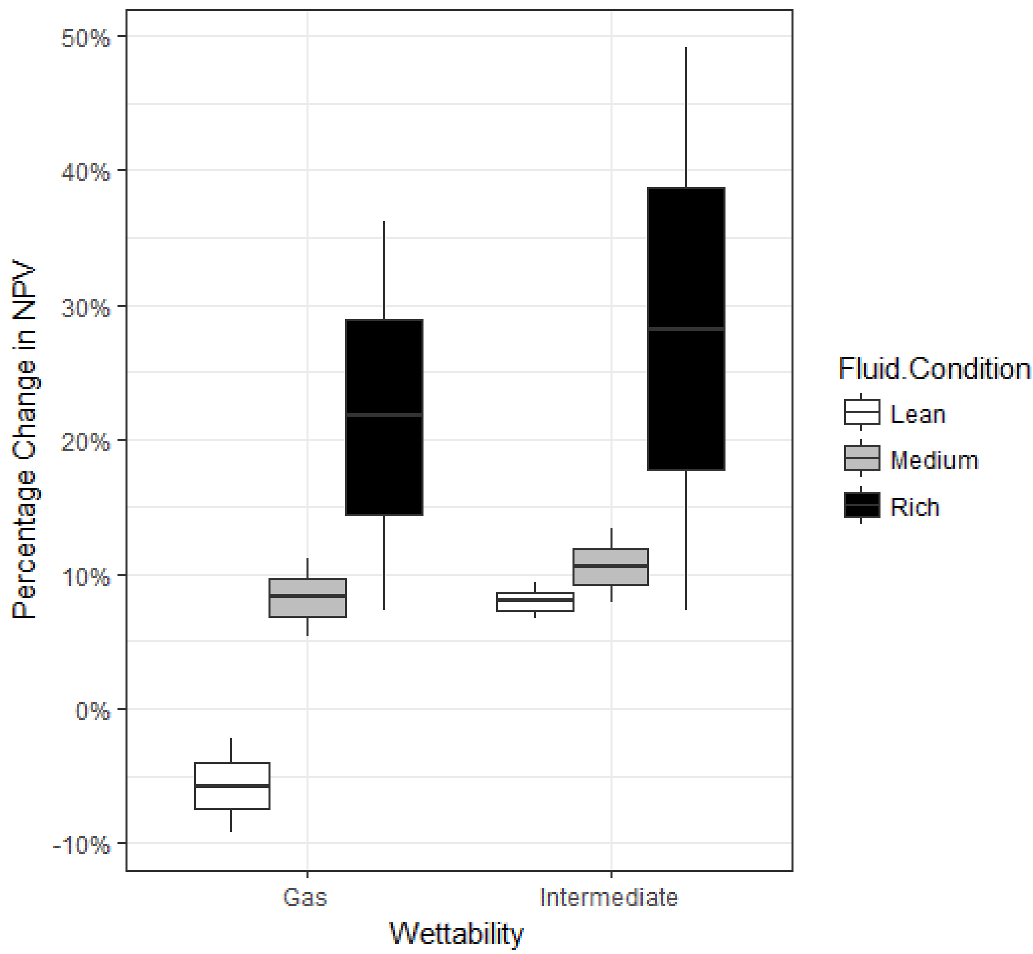


Figure 4-62: performance of wettability alteration treatment for 15000-ft reservoir by fluid type

Chapter 5: Screening Criteria for Various Factors

In this chapter, we attempt to establish screening criteria for various factors that could influence wettability alteration treatment. The use of 2^k design and analysis of experiment was used in this study - Two levels of each factor were considered and production using the combinations of these factors were modeled. The result was subject to statistical test to evaluate if the influence of each factor and their interactions were statistically significant.

5.1 DESIGN AND ANALYSIS OF EXPERIMENT.

The design and analysis of experiment was carried out to evaluate the influence of various reservoir and fluid factors on the performance of wettability alteration and to ascertain if there is a statistical difference in wettability treatment performance between different levels across these factors. The 2^k factorial design was used in this analysis and factors considered include reservoir size, permeability, wetting type, and treatment radius; thereby, giving rise to a 2^4 factorial design, and the experiment would be repeated across three different fluid types characterized by their yield. The high and low levels of across each factor are summarized in **table 5-1** below.

Table 5-1 Levels of factors used in the experiment

Factors	Low level	High level
Reservoir size (A)	2000 ft.	15000 ft.
Treatment radius (B)	5 ft.	15 ft.
Permeability (C)	10 md	100 md
Wetting type (D)	Intermediate	Gas

The high and low levels of the factors were chosen to replicate what is practically feasible in the field and to reduce the variance in the estimate of the slope between these two points. Two replicates of the experiments were carried out using the CMG software with all parameters being the same but changing the maximum time step (DTMAX) from 0.5 day to 0.75 day.

The 2^k factorial design uses the F-test to evaluate if each of the specified factors or independent variables and their interactions affect the response or dependent variable. It estimates a test statistic from the samples mean and standard deviation of the factors and compares to the critical value. A closely related parameter to the test statistic and the critical value is the p-value and the significance level (commonly denoted as α), used to determine if there is a statistically significant association between the response variable and each independent variable. The significance level is often set at 5% which connotes a 5% risk of concluding that a particular factor influence response when there is no actual relationship between the two variables. The null and alternative hypothesis for the main effect of each factor in a 2^k factorial analysis is summarized below

$$\mathrm{H_0}\text{: There is no significant difference in response based on an independent factor}$$
$$\mathrm{H_a}\text{: There is a significant difference in response based on an independent factor}$$

In other words, the null hypothesis is stating that the different levels of the independent variable do not influence the response variables while the alternative hypothesis asserts that the response variables differ across the two levels of the independent variables. The null hypothesis is accepted when $p - value > \alpha,$ this indicated there is a statistically significant association between $factor_i$ and the response. We fail to accept the null hypothesis when $p - value \leq \alpha$ and conclude that there is no statistically significant association between a factor and the response

The null hypothesis of the main effects of the four factors unique to this factorial design is summarized below:

$$H_0\text{: There is no significant difference in the effectiveness of wettability alteration between a 2000 ft. or 15000 ft. reservoir}$$

$$H_0\text{: There is no significant difference in the effectiveness of wettability alteration between a 5ft or 15ft treatment radius}$$

$$H_0\text{: There is no significant difference in the effectiveness of wettability alteration between a reservoir with a permeability of 10 md. or 100 md.}$$

A selected null hypothesis of the interaction effect of the independent variables is summarized below

$$H_0\text{: There is no significant effect of the interaction of reservoir size and treatment of radius on effectiveness wettability alteration in production enhancement in a gas reservoir}$$

$$H_0\text{: There is no significant effect of the interaction of reservoir size, treatment radius, permeability and wetting type in the effectiveness of wettability alteration in production enhancement in a gas reservoir}$$

It should be noted that in this analysis, the gas and the condensate are of economic importance, and the net present value of the 20-year ultimate gas and condensate recovery was used to evaluate the effectiveness of the wettability alteration in treatment. The results are expressed as a percentage change in NPV when compare to the expected NPV if the well was not treated. We first share in the next three sub-sections the results of this analysis, followed by a detailed discussion of the implications.

5.2 LEAN FLUID.

Figure 5.2 shows a summary of the results for all 32 simulation runs for lean fluid. From a quick glance at the table, intermediate wetting (IW) consistently outperformed gas wetting (GW), and at some points, the gas wetting gave a poorer production than the default liquid wetting state. **Table**

5.3 is the table for the analysis of variance (ANOVA) calculated from the data in **Table 5.2** and helps to estimate the significance of the effect of each factor or their interaction on the effectiveness of wettability treatment using the p-value yardstick.

Table 5-2 results for the performance of wettability treatment for lean gas reservoir

A	2000ft								15000ft							
B	5ft				15ft				5ft				15ft			
C	10md		100md		10md		100md		10md		100md		10md		100md	
D	IW	GW	IW	GW	IW	GW	IW	GW	IW	GW	IW	GW	IW	GW	IW	GW
	5.41%	2.26%	0.09%	-0.13%	3.88%	-0.45%	-1.26%	-2.52%	8.66%	-8.37%	9.78%	-1.39%	8.32%	-8.94%	9.78%	-1.49%
	5.35%	2.22%	0.28%	-0.09%	3.84%	-0.48%	-1.00%	-2.38%	8.60%	-8.37%	9.80%	-1.40%	8.29%	-8.93%	9.75%	-1.49%

Table 5-3 ANOVA table for wettability treatment of lean gas reservoir

Source	SS	DF	MSE	F-value	P-value
A	0.0135	1	0.0135	16.31	0.000189
B	0.0001	1	0.0001	0.10	0.758022
C	0.0010	1	0.0010	1.20	0.279201
D	0.0010	1	0.0010	1.16	0.28645
AB	0.0039	1	0.0039	4.70	0.035138
AC	0.0001	1	0.0001	0.10	0.758664
AD	0.0283	1	0.0283	34.18	4.03E-07
BC	0.0000	1	0.0000	0.03	0.86965
BD	0.0125	1	0.0125	15.03	0.000314
CD	0.0006	1	0.0006	0.71	0.40292
ABC	0.0000	1	0.0000	0.00	0.967335
ABD	0.0004	1	0.0004	0.53	0.468874
BCD	0.0000	1	0.0000	0.00	0.980647
ABCD	0.0000	1	0.0000	0.00	0.999914
Error	0.0406	49	0.0008	1.00	
Total	0.1020	63	0.0016		

The estimated p-value for reservoir size is lesser than the significance level of 0.05, hence we can conclude that there is a statistically significant association between the reservoir size and the effectiveness of wettability alteration treatment to enhance a gas reservoir containing a lean fluid. While the p-value of the main effect of treatment radius and wetting type is higher than our alpha value, the p-value of the interaction of reservoir size and treatment radius is less than 0.05, hence we can reject the null hypothesis and conclude that there is statistically no significant difference in the effectiveness of wettability alteration between a 5 ft. or 15 ft. treatment radius. The p-value of the interaction of treatment radius and wetting type, also the p-value of the wetting type and reservoir size are less than that of the significance levels which give us ground to conclude that there is an association between wetting type and performance of wettability alteration in a gas reservoir containing lean fluid. The p-value of the main effect of permeability and its interaction with any of the other factors from **Table 5-2** is consistently larger than our alpha value of 0.05, hence we fail to reject the null hypothesis for this variable and conclude that the permeability does not influence the performance of wettability alteration treatment in a gas reservoir containing lean fluid.

5.3 MEDIUM FLUID.

The results summarized in **Table 5-4** shows intermediate wetting being the better wetting option and wettability alteration of 10 md. reservoir outperforming treatment of a 100 md. reservoir.

Table 5-4 results for the performance of wettability treatment for medium gas reservoir

A	2000ft								15000ft							
B	5ft				15ft				5ft				15ft			
C	10md		100md		10md		100md		10md		100md		10md		100md	
D	IW	GW	IW	GW	IW	GW	IW	GW	IW	GW	IW	GW	IW	GW	IW	GW
	6.32%	4.26%	-0.01%	-0.30%	7.17%	3.91%	-1.01%	-2.02%	18.37%	22.30%	12.98%	-0.01%	7.66%	7.40%	9.81%	8.20%
	6.32%	4.26%	-0.11%	-0.22%	7.17%	3.91%	0.00%	-2.04%	18.37%	22.30%	12.98%	-0.01%	7.66%	7.40%	9.81%	8.20%

From the ANOVA **Table 5-5**, it can be seen that the p-values of reservoir size, treatment radius, permeability, and wetting type are less than 0.05 which indicates that the main effects of these factors are statistically significant at 95% confidence interval. Hence, we can conclude that there is a statistically significant difference in the effectiveness of wettability alteration to enhance gas production across the two levels of each of these factors in a reservoir containing medium fluid

Table 5-5 ANOVA table for wettability treatment of medium gas reservoir

Source	SS	DF	MSE	F-value	P-value
A	0.0010	1	0.0010	11.60	0.001324
B	0.0303	1	0.0303	348.66	6.36E-24
C	0.0062	1	0.0062	71.24	4.09E-11
D	0.0576	1	0.0576	662.25	4.03E-30
AB	0.0027	1	0.0027	30.88	1.12E-06
AC	0.0003	1	0.0003	3.11	0.084237
AD	0.0002	1	0.0002	2.18	0.146576
BC	0.0098	1	0.0098	112.16	2.9E-14
BD	0.0000	1	0.0000	0.01	0.926733
CD	0.0044	1	0.0044	51.03	3.98E-09
ABC	0.0030	1	0.0030	34.34	3.84E-07
ABD	0.0060	1	0.0060	68.52	7.21E-11
BCD	0.0139	1	0.0139	159.84	4.84E-17
ABCD	0.0031	1	0.0031	35.36	2.83E-07
Error	0.0043	49	0.0001	1.00	
Total	0.1428	63	0.0023		

Interestingly, the interaction of each of these factors with another proved to have significant influences on the effectiveness of wettability alteration except for reservoir radius-permeability, reservoir radius-wetting type, and treatment radius-wetting type interactions. The interaction of any 3 of the 4 factors would also significantly affect the performance of wettability alteration as established by their p-values.

5.4 RICH FLUID.

The results presented in **Table 5-6** is very much consistent with that of lean and medium fluids. Intermediate wetting is the optimal wetting condition for a gas reservoir containing a rich fluid

Table 5-6 results for the performance of wettability treatment for rich gas reservoir

A	2000ft								15000ft							
B	5ft				15ft				5ft				15ft			
C	10md		100md		10md		100md		10md		100md		10md		100md	
D	IW	GW	IW	GW	IW	GW	IW	GW	IW	GW	IW	GW	IW	GW	IW	GW
	2.96%	2.80%	2.71%	1.18%	3.42%	0.65%	0.83%	-2.30%	32.84%	23.80%	23.38%	20.72%	43.67%	37.35%	23.27%	20.53%
	4.66%	3.59%	1.31%	-0.80%	1.21%	-1.53%	0.36%	-3.94%	26.72%	23.07%	17.99%	15.38%	45.37%	39.48%	23.63%	21.68%

The reservoir radius, treatment radius, permeability and wetting type are all statistically significant at 95% confidence interval as their p-values are less than 0.05, hence we can conclude that they will influence the effectiveness of a wettability alteration in a gas condensate reservoir containing rich fluid as established in **Table 5-7**. The influence of the interactions of any of the two factors is also statistically significant except for the reservoir size - treatment radius interaction, and reservoir size – permeability interaction. More so, the interaction of the four factors can be established to have no significant effect on the effectiveness of a wettability treatment in a gas reservoir with a rich fluid.

Table 5-7 ANOVA table for wettability treatment of rich gas reservoir

Source	SS	DF	MSE	F-value	P-value
A	0.0022	1	0.0022	8.12	0.006391
B	0.0482	1	0.0482	180.44	4.76E-18
C	0.0083	1	0.0083	30.92	1.1E-06
D	0.5558	1	0.5558	2082.74	8.23E-42
AB	0.0004	1	0.0004	1.31	0.257315
AC	0.0002	1	0.0002	0.57	0.452933
AD	0.0009	1	0.0009	3.39	0.071487
BC	0.0069	1	0.0069	25.87	5.76E-06
BD	0.0238	1	0.0238	89.29	1.27E-12
CD	0.0258	1	0.0258	96.58	3.58E-13
ABC	0.0000	1	0.0000	0.00	0.95091
ABD	0.0012	1	0.0012	4.35	0.042202
BCD	0.0074	1	0.0074	27.68	3.14E-06
ABCD	0.0000	1	0.0000	0.00	0.964889
Error	0.0131	49	0.0003	1.00	
Total	0.6940	63	0.0110		

5.5 MAIN EFFECTS.

5.5.1 Main effects of reservoir radius

The performance of wettability alteration increases with the size of the reservoir as established in **Fig. 5-1.** The plot shows that regardless of the treatment type, large reservoir size will always outperform a small reservoir with respect to taking advantage of wettability alteration to improve productivity from a gas reservoir. On average, treating a 15000 ft. reservoir will result in about twice the increase in NPV in a reservoir containing lean fluid. Whereas, a reservoir containing medium fluid will result in a five-fold increase in production enhancement when a 15000 ft. reservoir is treated compared to a 2000 ft. gas reservoir. In addition, altering the default wetting state of a reservoir containing rich fluid will result in about thirty-fold increase production improvement for a large reservoir relative to a small reservoir as established in **Fig. 5.1**.

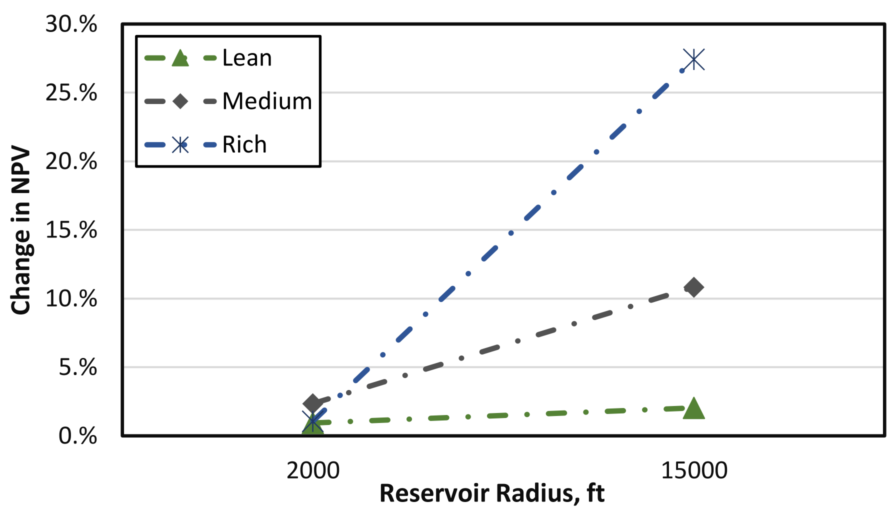


Figure 5-1 Main effect of reservoir size on wettability alteration treatment of gas reservoir

5.5.2 Main effects of treatment radius

Figure 5-2 shows that with respect to the well and reservoir parameters considered in the simulation model, a 5ft wettability alteration treatment is advisable for a gas reservoir containing lean and medium fluids, while a 15-ft treatment radius is an advisable option for rich fluids. From **Fig. 5-2**, as we move from 5-ft treatment to a 15-ft treatment, our 20-year NPV from the treated reservoir reduces by about 50% for a lean fluid and about 30% for a medium fluid. While as we move from a 5-ft treatment to a 15-ft treatment, will improve the 20-year NPV from a treated reservoir by about 35% as established in **Fig. 5-2.**

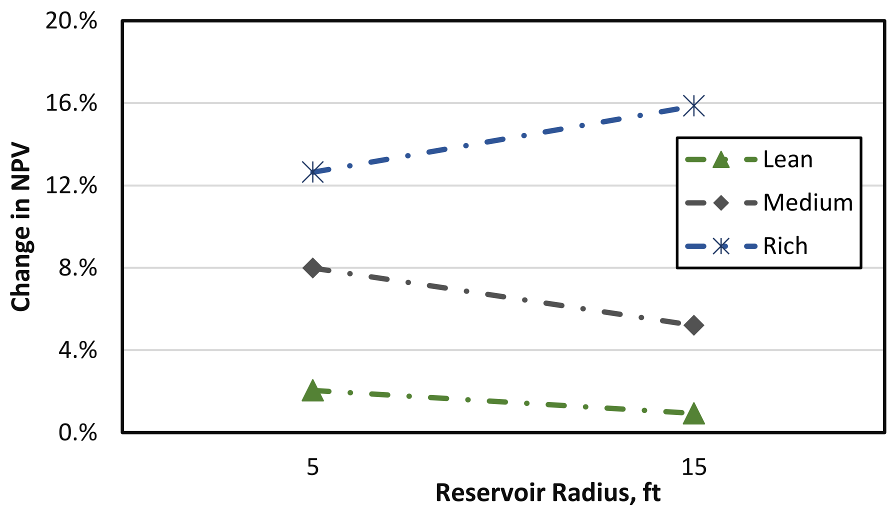


Figure 5-2 Main effect of treatment radius on wettability alteration treatment of gas reservoir

5.5.3 Main effects of permeability

The ease of flow within the gas reservoir also influences the performance of wettability alteration. As we move from a 10 md to a 100 md reservoir, **Figs. 5-3** establish that the trend in performance of wettability alteration differs with the fluid type. Moving from a 10 md. to a 100 md. permeability will almost triple the change in NPV due to wettability alteration when the reservoir contains lean fluid, while for a reservoir containing rich fluid, a 100 md treatment will results in additional 20%

in NPV enhancement compared to the reservoir with a permeability of 10 md as established from **Fig. 5-3**. Also, it can be established that moving from treating a 10 md to a 100 md permeability gas reservoir containing a medium fluid, the additional NPV gained by treatment decreases by about 28%.

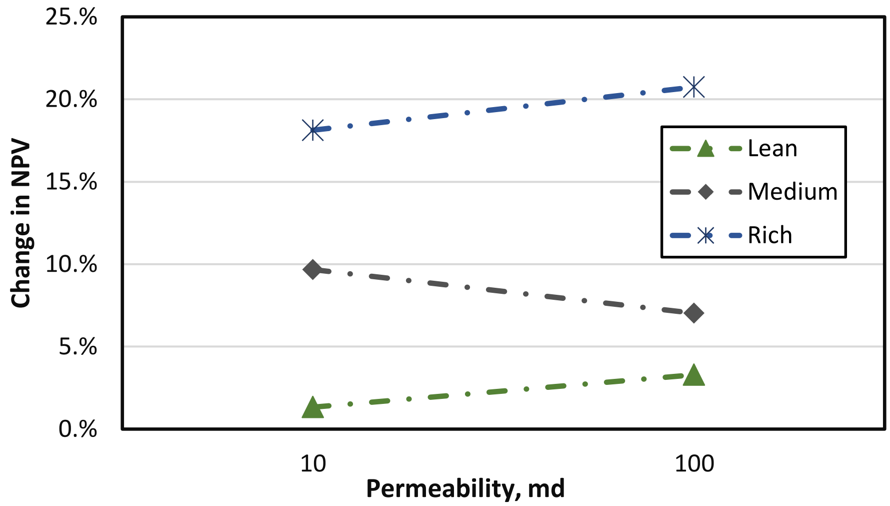


Figure 5-3 Main effect of permeability on wettability alteration treatment of gas reservoir

5.5.4 Main effects of wettability Type

The results from **Fig. 4** established that the optimal wetting type in a gas reservoir is the intermediate wetting irrespective of the liquid yield of the fluid contained in the reservoir. Gas treatment is also not advisable when a gas reservoir contains a lean fluid as it will result in poorer 20-year cumulative production and NPV as established in **Fig. 4.**

For a medium fluid, moving from an intermediate wetting condition to a gas wetting condition will result in about 30% fall in additional gas production, while a reservoir with rich fluid will experience in about 15% drop in additional combined gas and condensate production as we move from intermediate to gas wettability treatment of the gas reservoir.

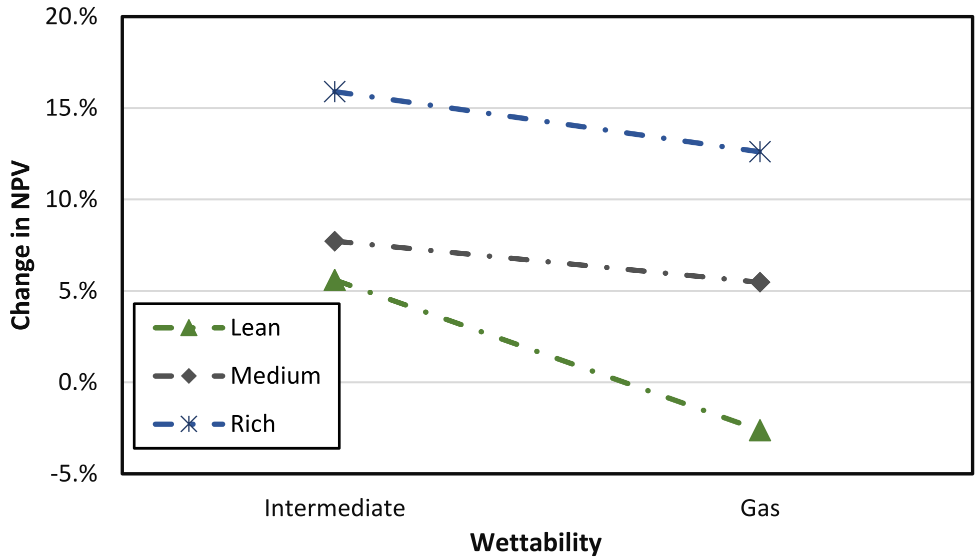


Figure 5-4 Main effect of wetting type on wettability alteration treatment of gas reservoir

5.6 INTERACTION OF FACTORS.

5.6.1 Effects of reservoir radius and permeability

Figure 5-5 shows the interaction effect of reservoir radius and permeability on the performance of wettability alteration in gas reservoir across the three fluid types. **Fig. 5-5** shows that the effect of reservoir radius on the performance of wettability alteration differs across the two permeability considered in our model for a reservoir with lean fluid. Given the fact the slopes of the plots in **Fig. 5-5** are similar, we can establish that for a gas reservoir containing medium fluid, the effect of reservoir size on the performance of wettability alteration treatment is the same regardless of the permeability (unless this is considered in terms of percentage change, in which case the effect in high permeability is more significant). We could recall from **Table 5.5**, the p-value from the analysis also indicated that the interaction of reservoir radius and permeability is not significant for a medium fluid. A similar observation is made in the case of rich fluids.

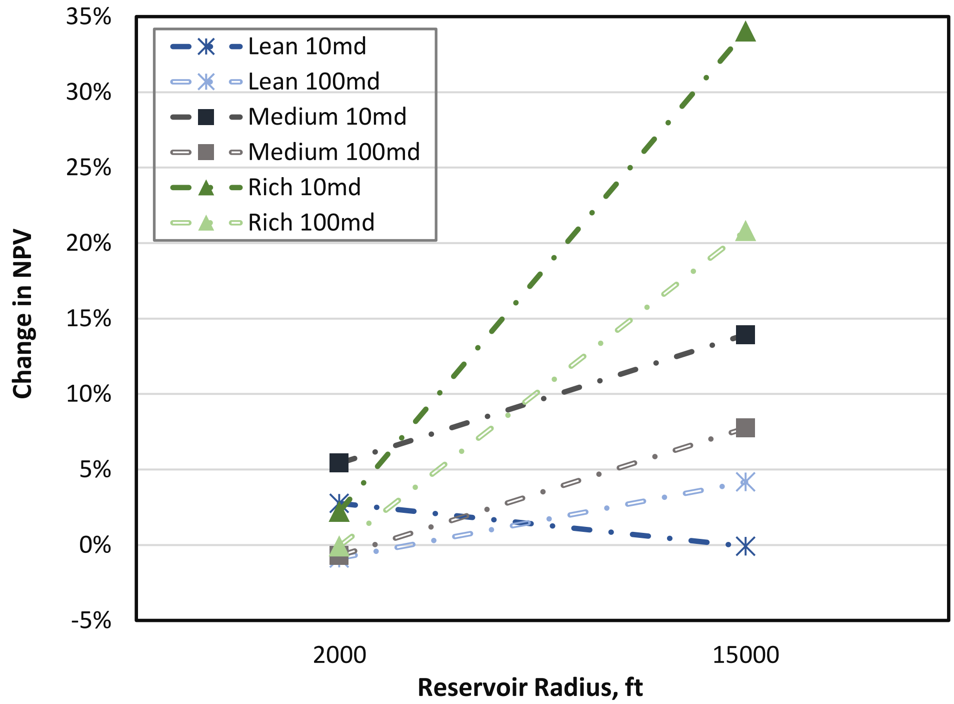


Figure 5-5 Interaction effect of reservoir radius and permeability on wettability alteration treatment of gas reservoir

5.6.2 Effects of the interaction of reservoir radius and treatment radius

Figure 5-6 shows the interaction effects of reservoir size and treatment radius on the effectiveness of wettability alteration treatment in a gas reservoir. The slopes of the lines across the three plots are different and these indicate that the reservoir size affects wettability alteration differently based on the treatment radius regardless of the fluid contained in the reservoir. A very good example can be seen in **Fig. 5-6** for rich fluid. A 5-ft treatment radius is advisable for a 2000 ft. reservoir while a 15-ft treatment radius is recommended for a very large reservoir.

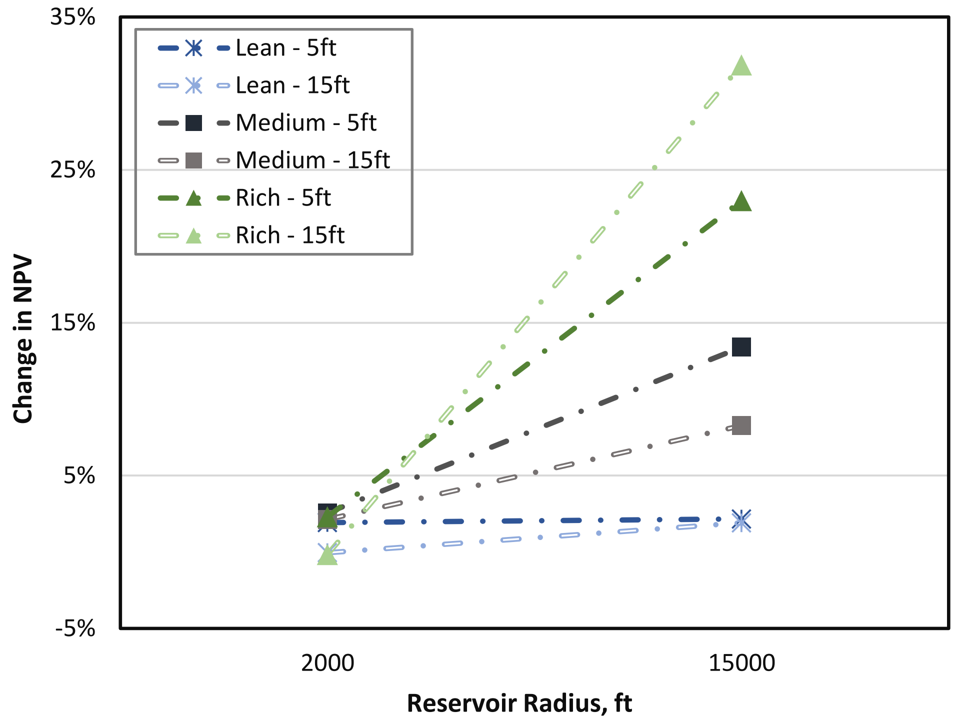


Figure 5-6 Interaction effect of reservoir and treatment radius on wettability alteration treatment of gas reservoir

5.6.3. Effects of interaction of reservoir radius and wettability type

Figure 5-7 shows the interaction effect of reservoir size and wetting type on the performance of a wettability alteration campaign in a gas reservoir. From **Fig. 5-7**, it can be seen that the slope of lines in the plots is fairly similar, hence we can argue that the intermediate wetting will consistently outperform gas wetting regardless of the reservoir size for a gas reservoir containing either a medium or rich fluid. This assertion also agrees with the information from **Table 5.5** and **Table 5.7**. The p-values of the interaction of these factors indicate they are not statistically significant. From **Fig. 5-7**, there is a clear interaction effect of the factors on the performance of wettability alteration as the slope of the line differs. For smaller gas reservoir containing lean fluid, with a drainage radius less than 2000 ft., the optimal wetting condition could be excepted to be a gas wetting.

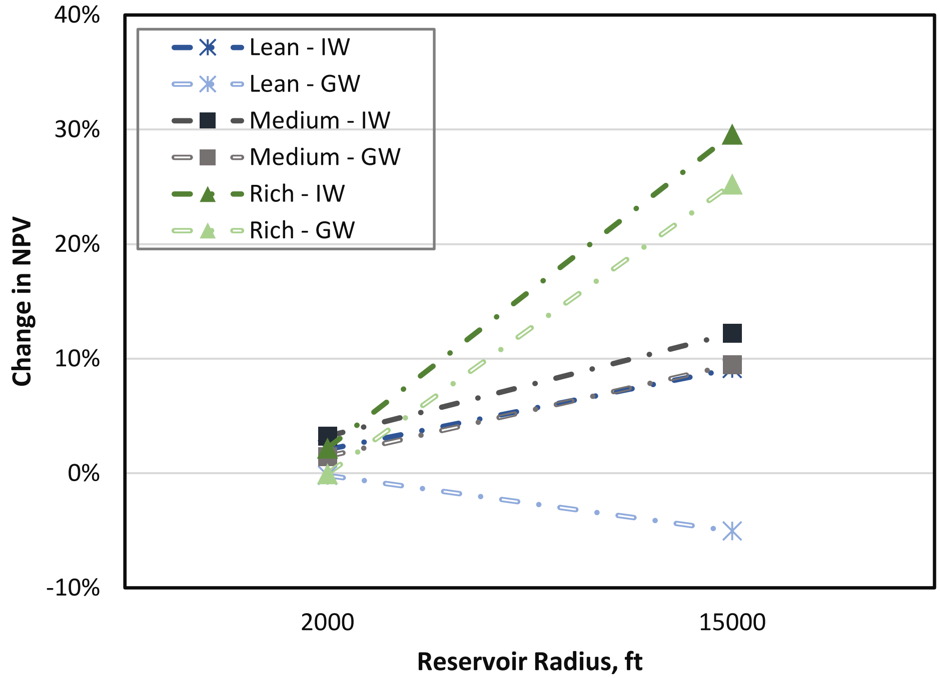


Figure 5-7 Interaction effect of reservoir radius and wetting type on wettability alteration treatment of gas reservoir

5.6.4. Effects of interaction of permeability and treatment radius

We can establish than the influence of the permeability on the performance of wettability alteration differs with the treatment radius when we examine **Fig. 5-8**. The slopes of the lines within the plot for the three fluids differ. The performance of wettability alteration treatment for a 100 md reservoir containing rich fluid is fairly similar regardless of the treatment size but a 5-ft treatment is clearly the optimal option if it were to be a 10 md reservoir as established in figure 8c. While from figure 8b for a reservoir containing medium fluid, 5 ft. is the optimal treatment radius for 10-md reservoir while a 15 ft. treatment is advisable if the permeability is 100 md.

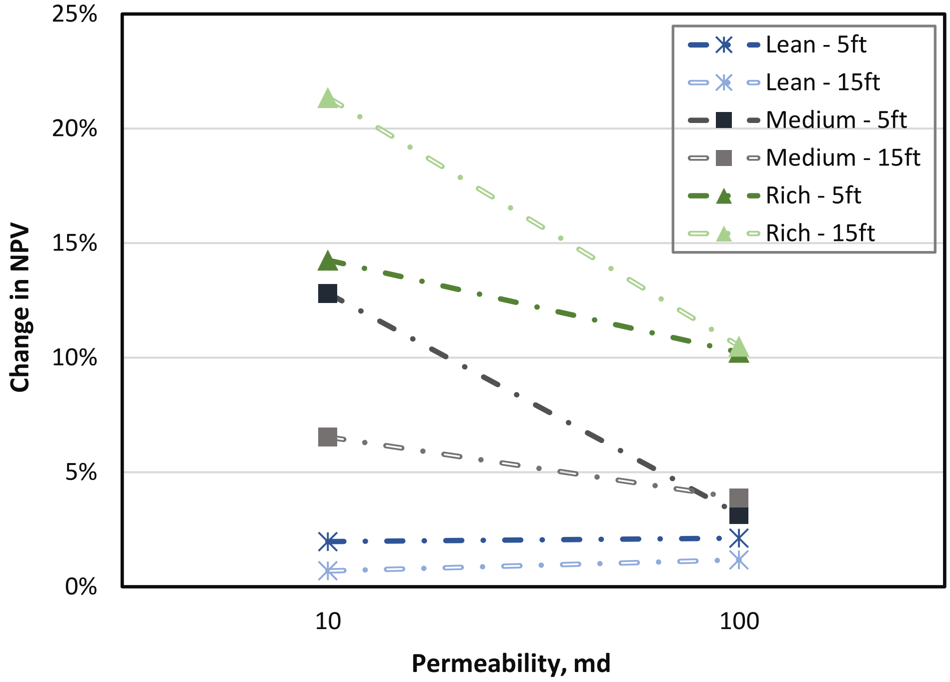


Figure 5-8 Interaction effect of permeability and treatment radius on wettability alteration treatment of gas reservoir

5.6.5. Effects of interaction of permeability and wettability type

Fig. 5-9 shows the interaction effect of permeability and the wetting type on the effectiveness of wettability alteration effort in enhancing production from a gas reservoir. The slopes of the lines within the three plots indicates the performance of each wetting type differs with the permeability of the reservoir across each fluid type. In this study, the intermediate wetting consistently outperforms the gas wetting, but a close look at the **Fig. 5-9**, the additional production due to treatment is somewhat similar to that of gas wetting when a medium fluid is contained in a 10 md reservoir. In addition, the performance of gas wetting improves as the permeability increases while the performance of intermediate wetting declines with increasing permeability when a lean fluid is contained in a gas reservoir as established in **Fig 5-9**.

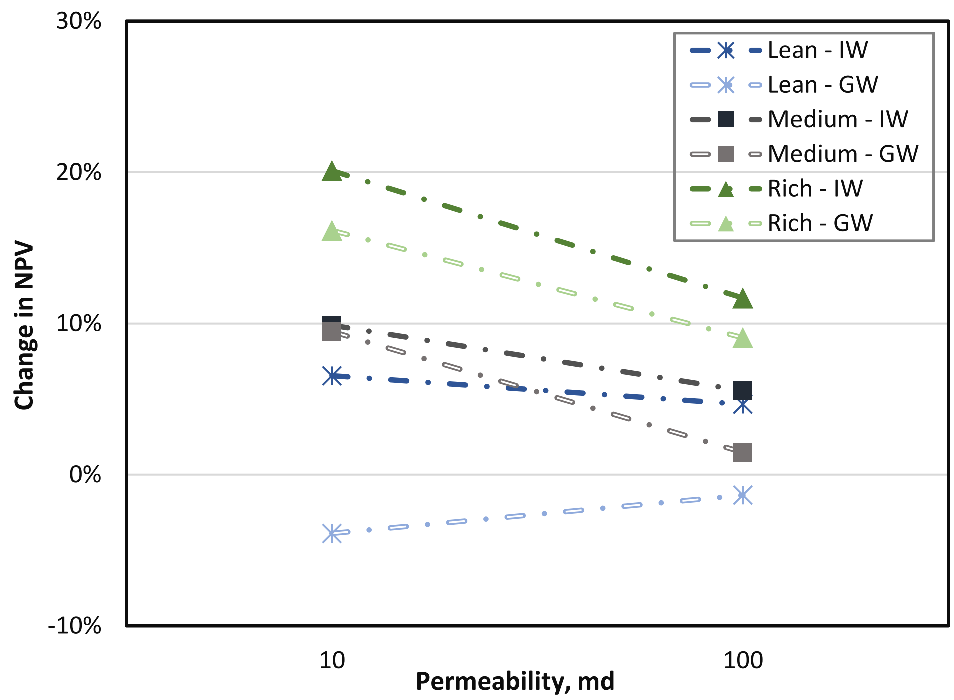


Figure 5-9 Interaction effect of permeability and wetting type on wettability alteration treatment of gas reservoir

5.6.6. Effects of interaction of treatment radius and wettability type

The interaction effect of treatment radius and wetting type can be seen in **Fig. 5-10**. The slopes of the lines are similar for plots in **Figure 5-10** indicating there is no interaction effect hence the performance of each wetting type does not vary with treatment radius when a gas reservoir containing lean or rich fluid treated. **Fig 5-10** shows that there is an interaction effect of wetting type and treatment radius on the performance of wettability treatment when the gas in the reservoir is a medium fluid. However, recalling that the p-value of the interaction effect from **Table 5.5** established the interaction effect of wetting type and treatment radius for a treated gas reservoir containing medium fluid is statistically insignificant.

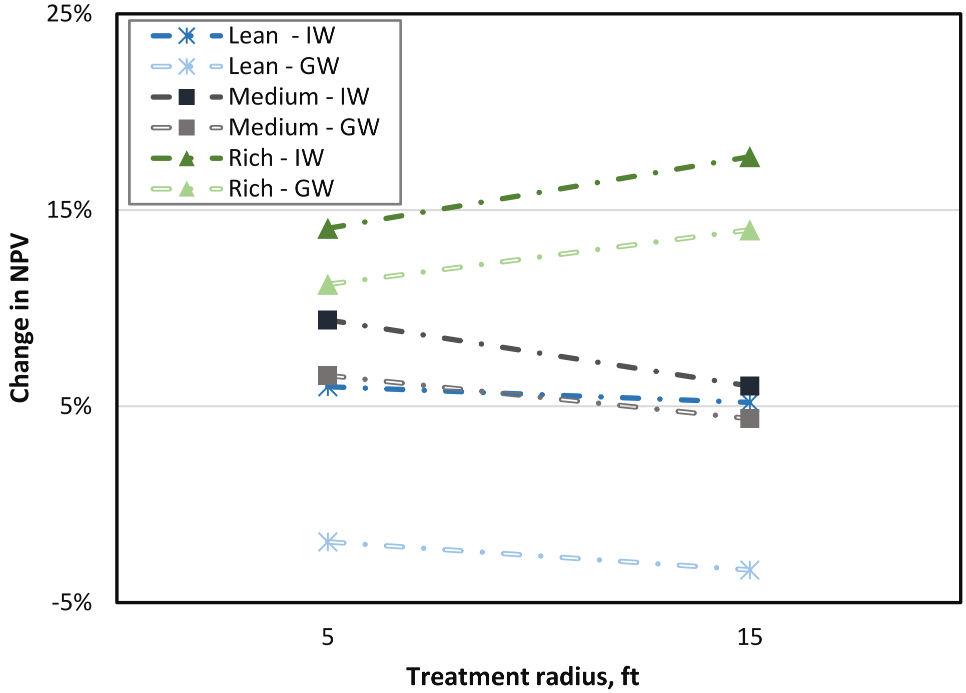


Figure 5-10 Interaction effect of treatment radius and wetting type on wettability alteration treatment of gas reservoir

Chapter 6: Well Spacing and Nodal Analysis

This chapter presents the analysis and results of the use of well spacing and wettability alteration to maximize well deliverability from gas condensate reservoir. Productions from three reservoir sizes were modeled using three fluids of distinct condensate yield. Production from default reservoir wetting state was compared to an altered wettability state across the reservoir fluid combinations. Nodal analysis was carried out to estimate the suitable flowrate and flowing bottom hole pressure in each case. The rates and pressure values from the nodal analysis serve as input for the production simulation. The results from liquid wetting were presented first followed by the results for intermediate wetting for the selected reservoir. The gas-wetting case was not considered in this chapter since intermediate wettability was identified earlier as a better altered-wetting state. We also limit the study in this chapter to the case of 10-md permeability. Comparisons were made on the bases of NPV analysis. Finally, well spacing analysis was carried out to evaluate the interplay between spacing and wettability in obtaining the maximum value from the reservoir.

6.1 NODAL ANALYSIS.

Nodal analysis was used to determine the suitable flow conditions of the wells in our simulation model. We wanted to link the reservoir performance to the limit of the well capacity to produce the reservoir fluid. Nodal analysis involves studying the relationship between the flow rate and the bottom hole pressure, considering the flow conditions in the wellbore, as well as the reservoir properties and potential. In the nodal analysis, the objective is to establish a point of intersection between the inflow performance relationship (IPR) and the tubing performance curve (TPC). The

IPR is the relationship between flowrates and bottom-hole pressure that is estimated from the reservoir model while the TPC gives the bottom hole estimations from the wellbore model.

Pipesim multiphase flow simulation software was used to estimate the BHP corresponding to some selected flowrates from the wellbore model, taking into account the GOR for each of the fluids considered. For this analysis, we limit our investigation for production through 3-inch tubing for all reservoir sizes. **Table 6-1** shows the parameters that were used as input in Pipesim, as well as those used in the IPR calculations.

Table 6-1: inputs for simulation and IPR calculations for each fluid type

	Lean	Medium	Rich
Reservoir depth	10000 ft.	10000 ft.	10000 ft.
Reservoir Temperature	220 F	220 F	220 F
Reservoir pressure	5500 psia	5500 psia	5500 psia
Tubing inner diameter	3 inches	3 inches	3 inches
Flowline inner diameter	3 inches	3 inches	3 inches
Tubing/Flow line thickness	0.5 inches	0.5 inches	0.5 inches
Gas Condensate yield	39.08 bbl/MMcf	96.06 bbl/MMcf	148.11 bbl/MMcf
Compressibility factor	1.04267 $Psia^{-1}$	1.04061 $Psia^{-1}$	1.04106 $Psia^{-1}$
Reservoir thickness	70 ft.	70 ft.	70 ft.
Well radius	0.33 ft.	0.33 ft.	0.33 ft.
skin	0	0	0
Viscosity	0.49 cp	0.749 c	0.793 cp
Surface pressure	100 psia	100 psia	100 psia
Surface temperature	65 F	65 F	65 F

$$\bar{p}^2 - p_{wf}^2 = \frac{1424 q \mu Z T}{kh}\left[\ln 0.472 \frac{r_e}{r_w} + s\right] \text{………………} \quad (6\text{-}1)$$

Equation 6-1 shows the Steady-state flow gas equation used to calculate the flowing bottom hole pressure given the fluid and reservoir properties in the IPR. The plots of the IPR and TPC for the three fluids, lean, medium, and rich, can be seen in **Figs. 6-1, 6-2,** and **6-3**, respectively. The equilibrium flowrate and bottom-hole pressure estimated from the nodal analysis were used as well as constraints for maximum flow rate and minimum BHP in the CMG model to simulate radial flow in a gas condensate reservoir.

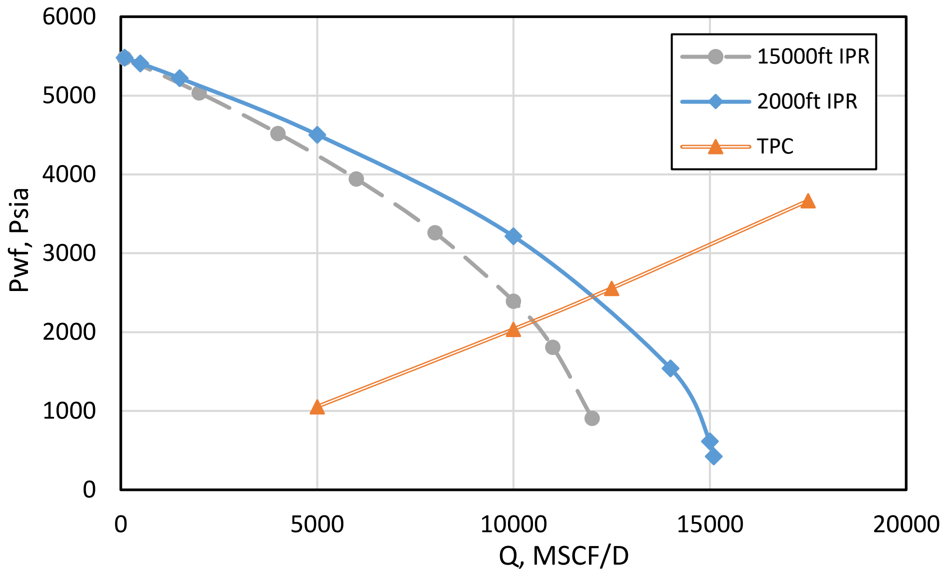


Figure 6-1. Nodal analysis for lean gas reservoir

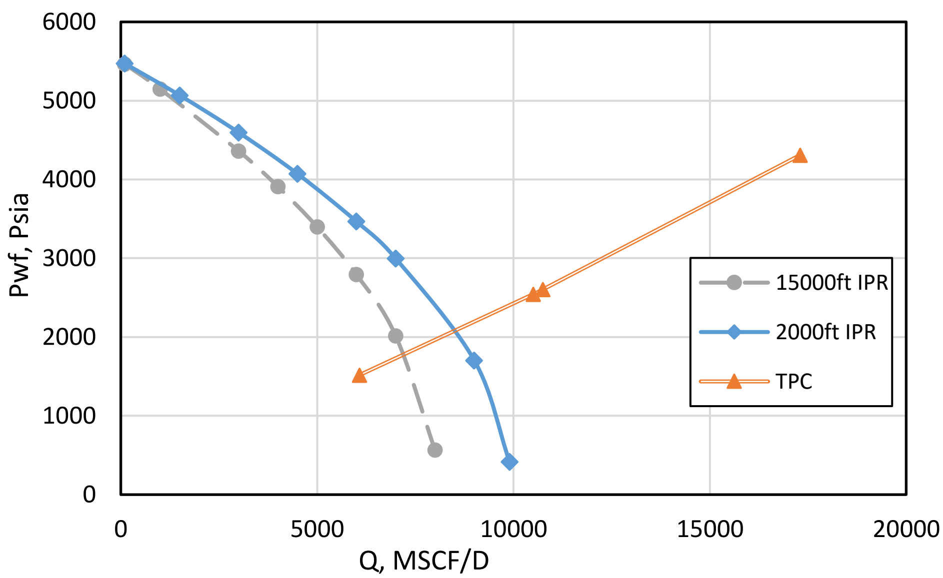


Figure 6-2. Nodal analysis for medium gas reservoir

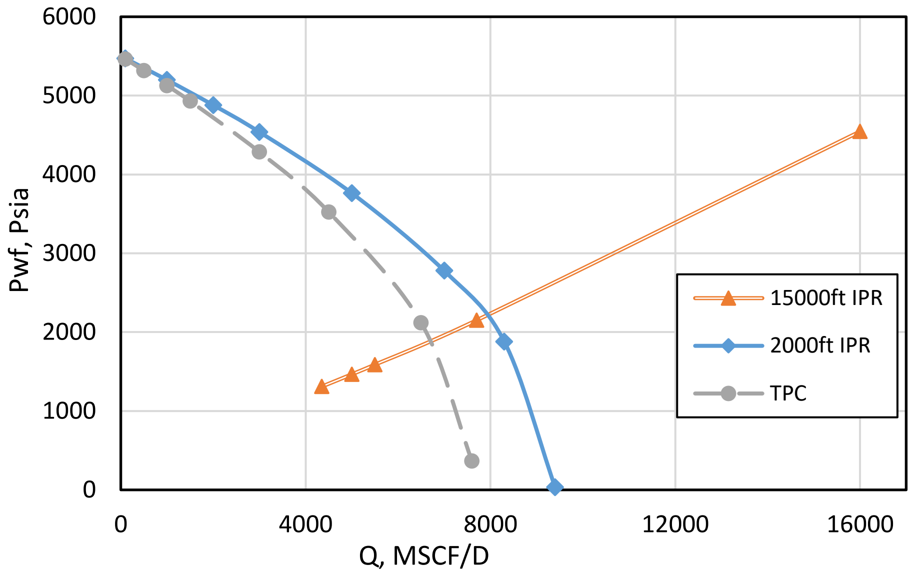


Figure 6-3. Nodal analysis for rich gas reservoir

6.2 SPACING ANALYSIS.

A simple geometric approach was used in well spacing analysis as illustrated in **Fig. 6-4**. We attempt to determine the minimum number of wells of smaller drainage area that can fit in the larger drainage area. For example, what is the minimum number of 2000-ft drainage radius wells can be placed within 6000-ft or 15000-ft radius reservoir without interference between the wells. Likewise, the minimum number of wells of 6000-ft drainage radius that could be placed in a giant 15000-ft reservoir. These numbers are used when comparing the recovery factors and NPVs from the various simulation runs. It was determined that comparing the 6000-ft and the 2000-ft results can be done with a multiplication factor of 5 and comparing the 6000-ft and 15000-ft results can be done with a multiplication factor of 4. On the other hand, comparing the 15000-ft case to the 2000-ft case is done with a multiple of 20.

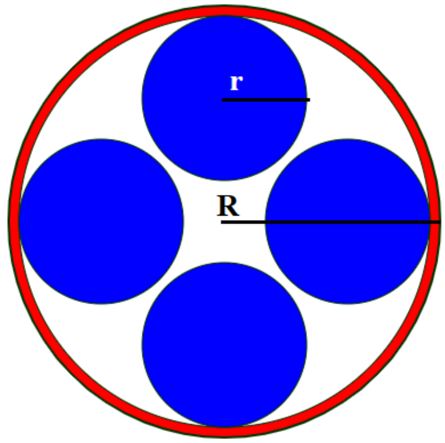


Figure 6-4. Radial well spacing analysis

6.3 PRODUCTION AT DEFAULT WETTING STATE.

In this section, we consider the production results from the original wetting state of the reservoir, and that is strong-liquid wetting. We show the results for variation in the size of the drainage area.

6.3.1 Lean gas condensate reservoir production at suitable operational conditions

Figure 6-5 shows the gas rate for the 20-year production from three lean gas reservoirs of different sizes at the flow rate and BHP estimated from the point of intersection of the inflow performance relationship of each reservoir and the tubing performance curve. The flowrate from the largest reservoir is sustained all through the production life considered for the well, while that of the medium reservoir size was sustained for some years before the rate starts dropping. The smallest reservoir experiences a decline in flowrate before others. It is to be noted that the decline in rates coincides with the point where the BHP of the well reaches the minimum BHP. The condensate drop at the near-wellbore region of the reservoir follows a similar pattern as the flowrates. **Figure 6-6** shows the condensate saturation at cell (1, 1, 1) in the radial reservoir model which corresponds to region within 0.1 ft. of the wellbore. The condensate saturation of the 15000-ft reservoir was 0% all through the 20-year production life of the well since the BHP didn't reach the dew point pressure of the reservoir fluid in this case.

Interestingly, the 6000-ft and 2000-ft reservoirs experienced condensate accumulation at the near-wellbore region of the reservoir at a later date in the production life of the well. The beginning of the formation of condensate at the reservoir coincides with the time the well starts experiencing a decline in gas flowrates and BHP reaches the dew point pressure value. The maximum condensate saturation is about 60% and 68% for the 2000-ft and 6000-ft reservoirs respectively, which put into perspective the extent of hampering of mobility the gas would encounter.

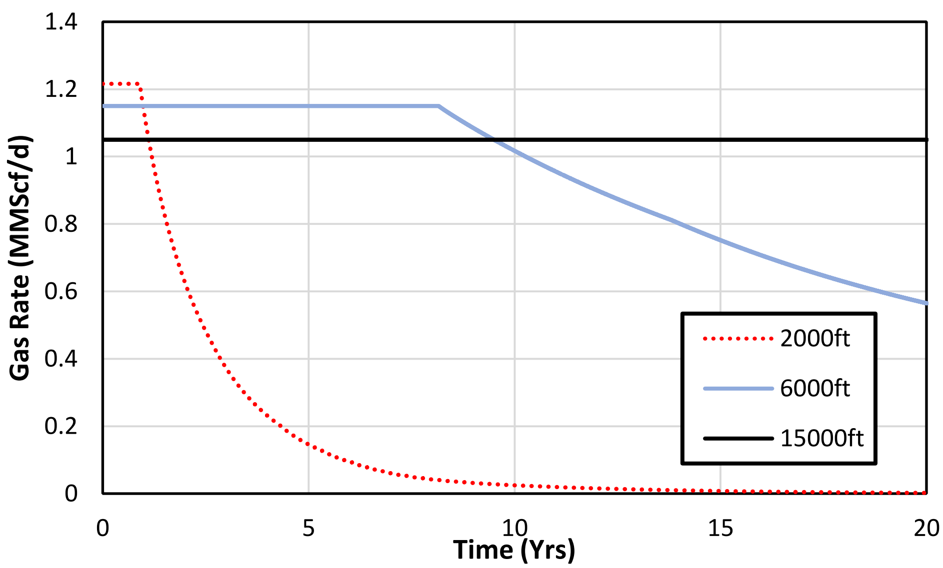


Figure 6-5. Gas rate from lean gas reservoirs at default reservoir wetting state

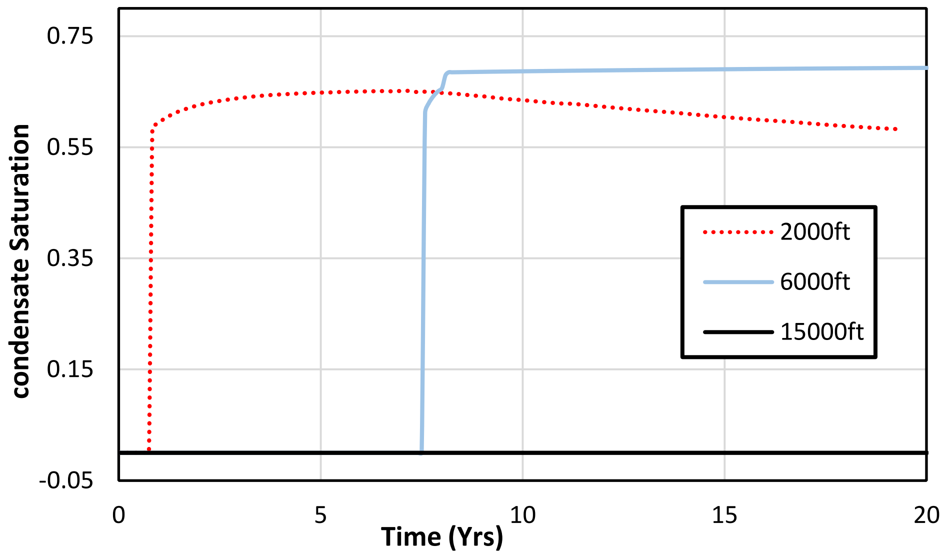


Figure 6-6. condensate saturation from lean gas reservoirs at default reservoir wetting state

6.3.2 Medium gas condensate reservoir production at operational conditions

Figure 6-7 presents the 20-year production from the three medium gas condensates reservoirs. In a pattern similar to that of the lean gas reservoir, the flow rate and BHP from the nodal analysis sustained the initial production rate from the largest reservoir all through the 20-year period, while the small reservoirs experience drop from the initial rates at some point within the production period. The 2000-ft radius reservoir started experiencing condensate accumulation within the 0.1 ft. region of the wellbore before the second year of production while that of the 6000-ft radius reservoir experienced near-wellbore condensate accumulation at about the third year. In both cases, maximum condensate saturation was about 80% of the pore volume. In addition, **Fig. 6-8** shows that the 15000-ft radius reservoir did not experience condensate accumulation throughout the production period.

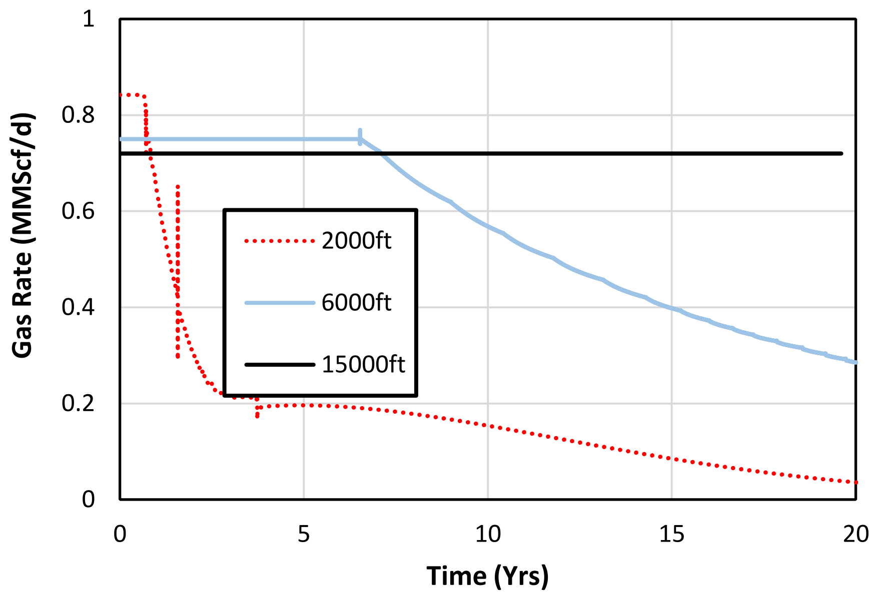


Figure 6-7. Gas rate from medium gas reservoirs at default reservoir wetting state.

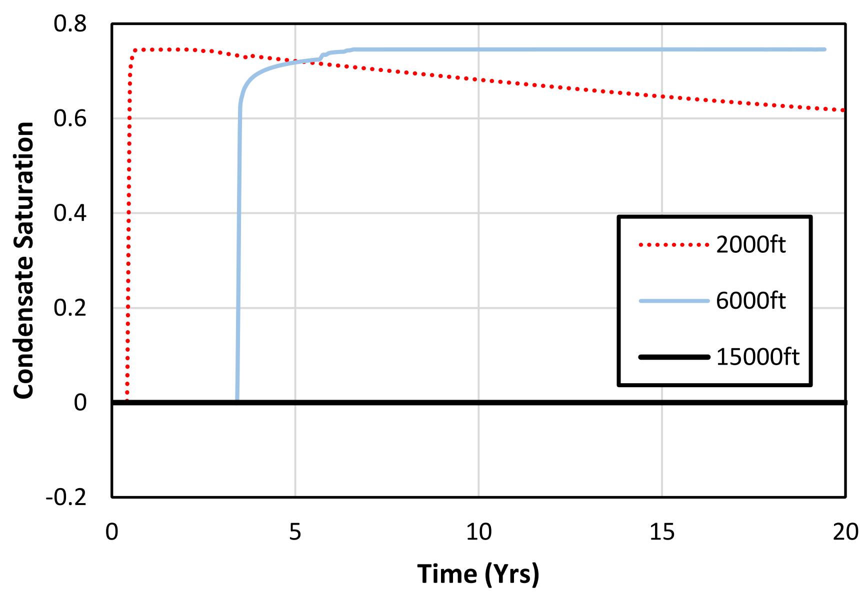


Figure 6-8. Condensate saturation from medium gas reservoirs at default reservoir wetting state

6.3.3 Rich gas condensate reservoir production at operational conditions

In a deviation from the observation for lean and medium gas reservoirs, **Fig. 6-10** shows that the 15000-ft radius reservoir experiences near-wellbore condensate accumulation at the start of production and arrives at a maximum condensate saturation of about 80% even before the first year of production. The other two rich gas reservoirs also experience condensate accumulation where the maximum saturation is achieved at about the same time as the 15000-ft radius rich gas condensate reservoir, but their condensate saturation declines with time. The plot of the gas rate shown in **Fig. 6-9** shows signs of instability in the model, however, the results obtained are reasonable and in line with the expected performance.

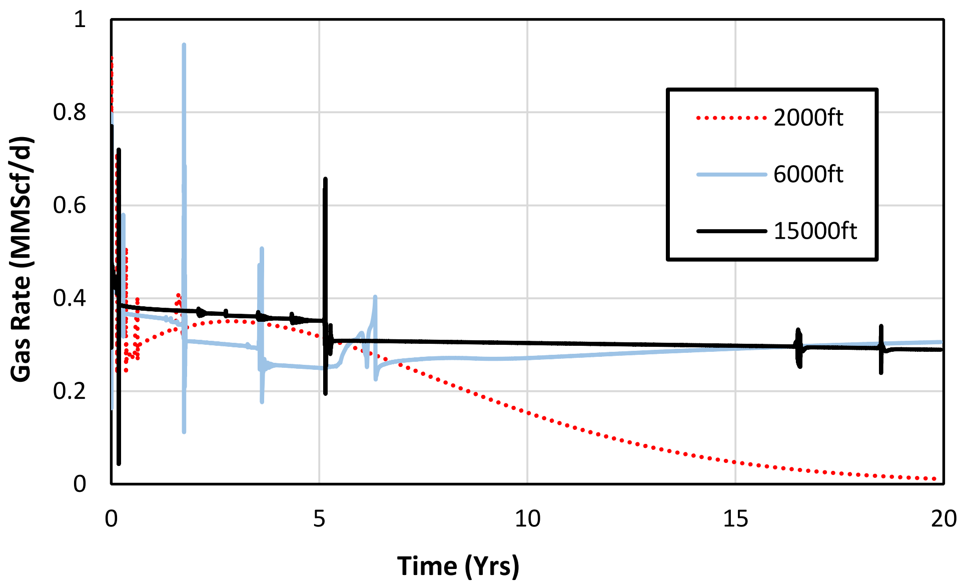


Figure 6-9. Gas rate from rich gas reservoirs at default reservoir wetting state

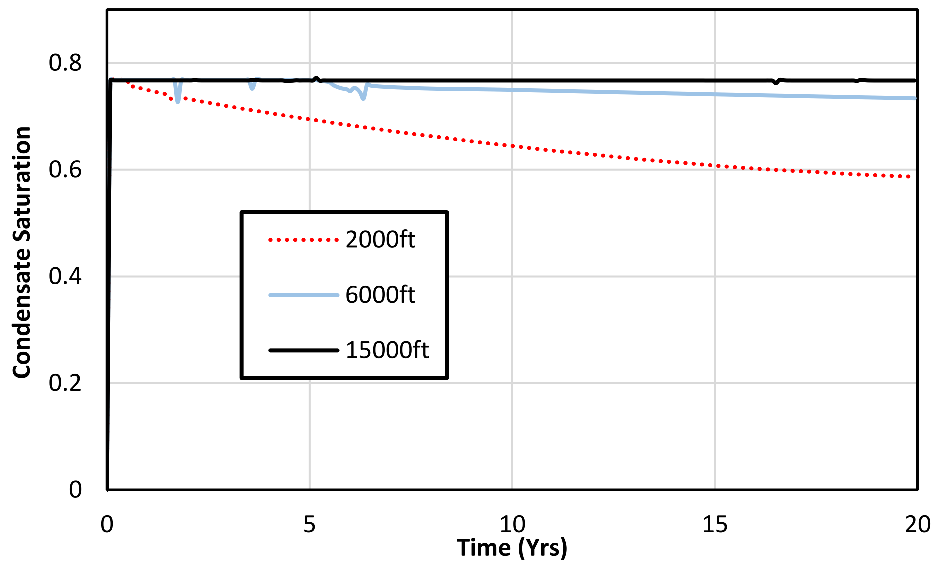


Figure 6-10. Condensate saturation from rich gas reservoirs at default reservoir wetting state

6.4 WETTABILITY TREATMENT.

In the previous section, and with the help of nodal analysis, production profiles were obtained for cases of wells producing from various drainage areas. Some fundamental questions need to be answered. will a single well drilled in a large gas condensate reservoir help maximize the ultimate hydrocarbon recovery from the reservoir? How does the recovery factor from multiple non-interacting wells compare to the recovery factor from a single well-draining a large reservoir, and how do we leverage well spacing and wettability alteration to improve ultimate recovery from the reservoir? **Sections 6.5.1 – 3** present the results for the impact of wettability alteration on well performance in the cases that experienced condensate accumulation when produced at the default liquid wetting state.

6.4.1 Intermediate wetting treatment of lean gas condensate wells

Figure 6-11 shows the flowrate from a lean gas well with drainage area radii of 2000 ft. and 6000 ft. The post-treatment near-wellbore saturation can be seen in **Fig. 6-12**. For the 6000-ft case, in comparison to the results presented in **Fig. 6-5**, the impact of wettability alteration is clear. The gas rate was sustained at the initial flowrate for an additional four years, and the near-wellbore condensate accumulation was delayed by two years with a maximum condensate saturation of less than 50%. Wettability alteration sustained the initial rate from the 2000-ft reservoir slightly but significantly reduced the maximum near-wellbore condensate saturation from about 60% to less than 40% reflecting the increase in liquid mobility.

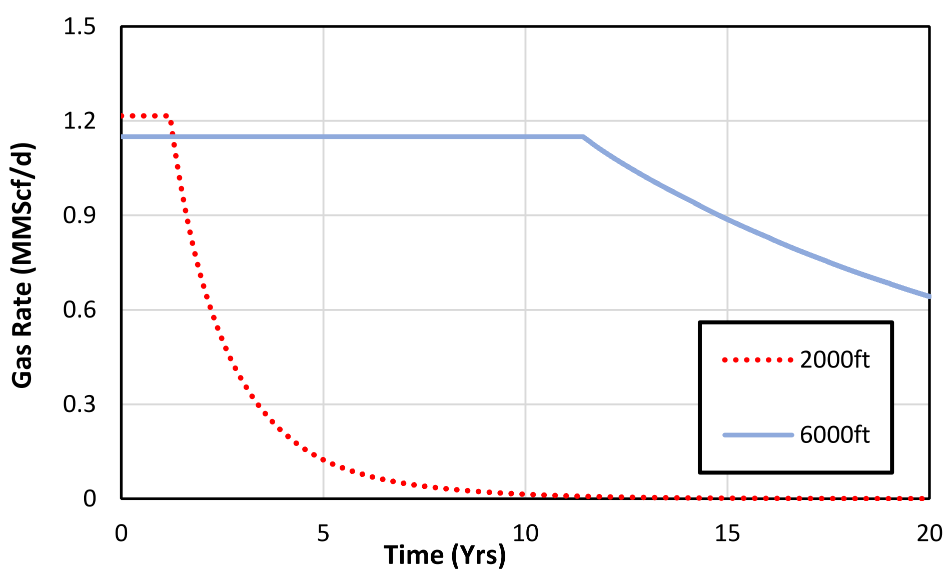


Figure 6-11. Gas rate from treated lean gas reservoirs at intermediate wetting conditions

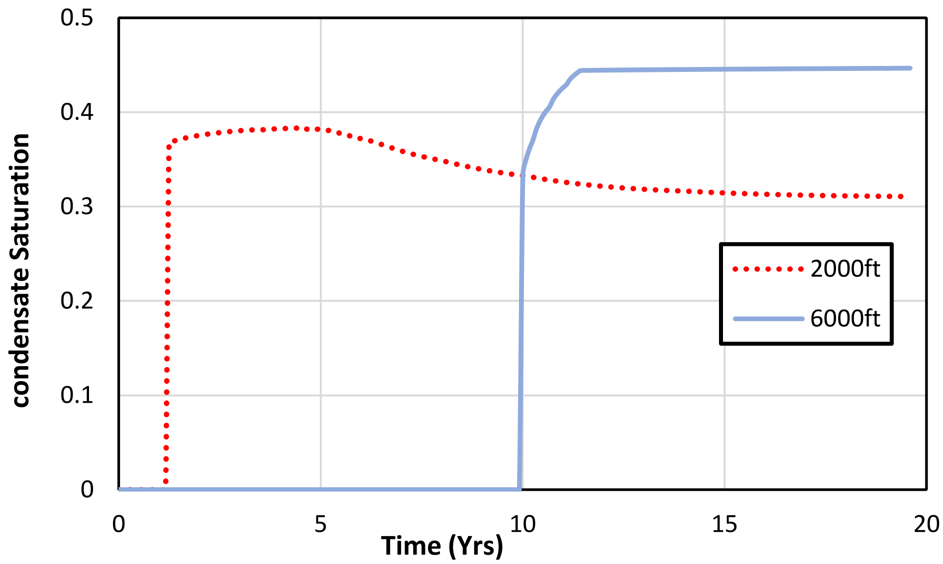


Figure 6-12. condensate saturation from treated lean gas reservoirs at intermediate wetting conditions

6.4.2 Intermediate wetting treatment of medium gas condensate reservoir

Figure 6-13 shows that intermediate wetting treatment sustained the initial production rate from 6000-ft radius reservoir for an additional 4 years while the maximum condensate saturation after treatment fell to 50%. Interestingly, intermediate wetting treatment of the 2000-ft reservoir only added less than a year of initial production rate but the liquid saturation was lowered considerably from about 80% to about 30%. The condensate saturation fell to about 10% in the later years of production from the 2000 ft. reservoir as established in **Fig. 6-14**.

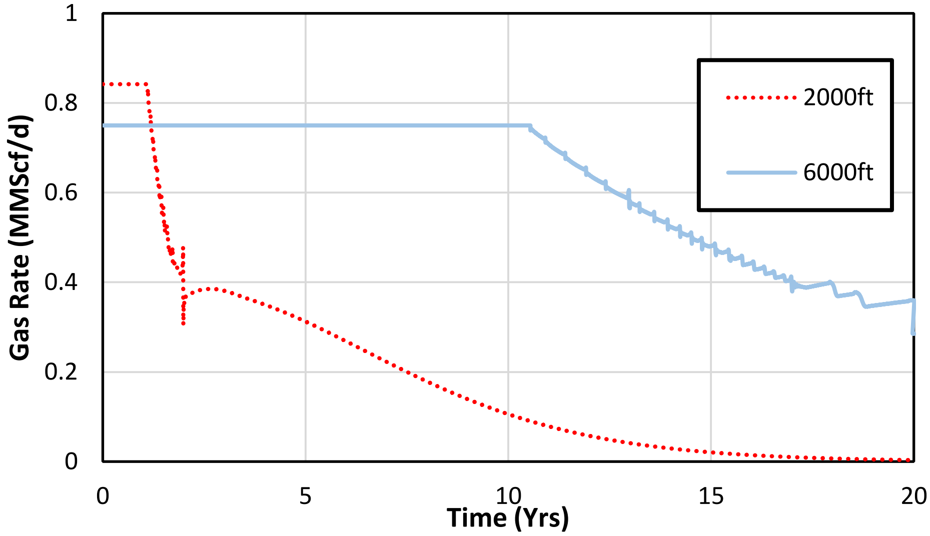


Figure 6-13. Gas rate from treated medium gas reservoirs at intermediate wetting conditions

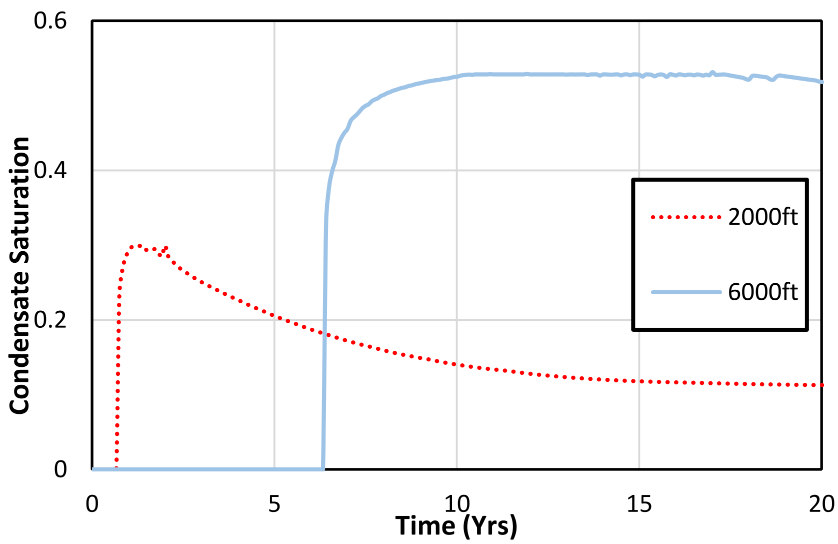


Figure 6-14. condensate saturation from medium gas reservoirs at intermediate wetting conditions

6.4.3 Intermediate wetting treatment of rich gas condensate reservoir

From **Fig. 6-15**, we observed that wettability alteration of the reservoir delays the sharp decline in production rates in all of the three reservoir sizes observed in **Fig. 6-9**. However, wettability treatment did not delay the commencement of condensate formation in the near-wellbore region as the accumulation of condensate started as production began regardless of the size of the reservoir as established in **Fig 6-16**. The maximum condensate saturation was however lowered by 20%.

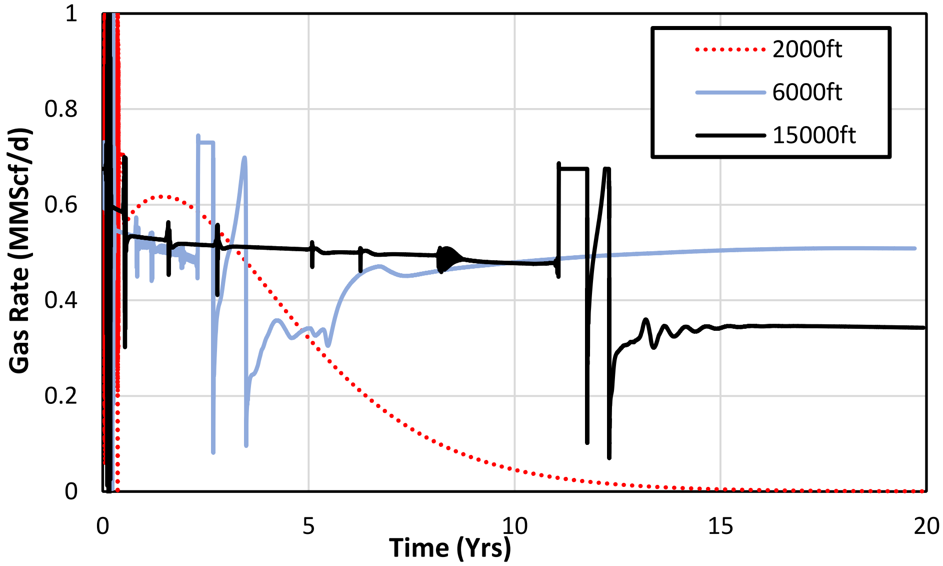


Figure 6-15. Gas rate from treated rich gas reservoirs at intermediate wetting conditions

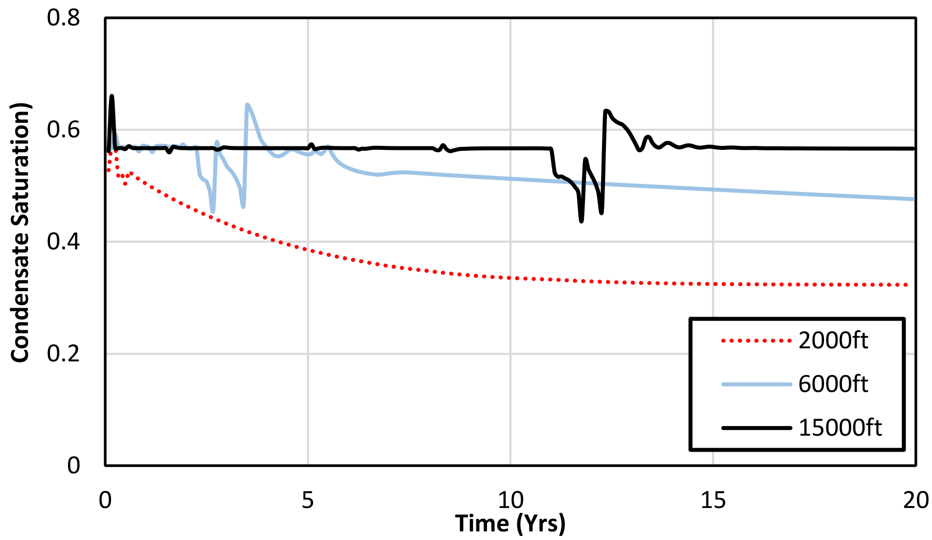


Figure 6-16. condensate saturation from treated rich gas reservoirs at intermediate wetting conditions

6.5 WELL SPACING AND ECONOMIC ANALYSIS.

Tables 6-3, 6-4, and **6-5** present the results for the 20-year production for the three reservoir gas types considered. The net present value is estimated from the average yearly flowrate according to the criteria described in chapter 3, the OOIP and OGIP are calculated based on volumetric data, and recovery factors are calculated from cumulative production numbers.

In order to better analyze this data, a graphical representation is rendered in **Figs. 6-16** and **6-17**. We will first consult the recovery factors. As shown in **Fig. 6-16**, wells with a smaller drainage area recover more of the oil and gas in place then wells with a larger area to drain over a period of 20 years. This data is further analyzed later in this section on how to space wells in such a formation. One would notice, as expected, that the oil recovery factor becomes lower than the gas recovery factor when the fluid is richer, while gas recovery increases for richer fluids. Consulting the NPV values for these cases, the medium fluid seems to offer the highest values for all drainage area sizes, compared to the lean and rich fluids. The larger recovery of heavy components seems to influence this observation.

The results shared in **Fig. 6-17** and **Fig. 6-18** represent the impact of near-wellbore wetting conditions on RF and NPV for wells with a 2000-ft drainage area. The change in the wetting condition does not seem to have a significant impact on the recovery factors, however, the NPV values show that intermediate wetting is superior. This is due to the increase in production rates of both oil and gas early in the life of the well. This effect is more significant in the case of medium and rich fluids and is not as significant in the case of lean fluids.

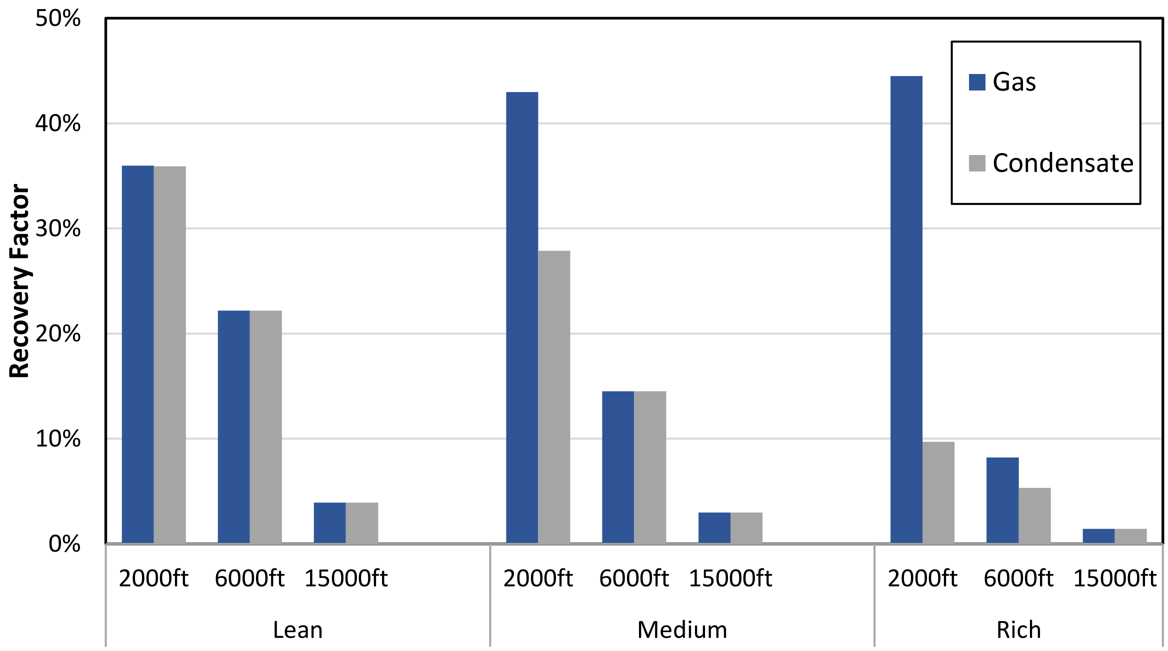
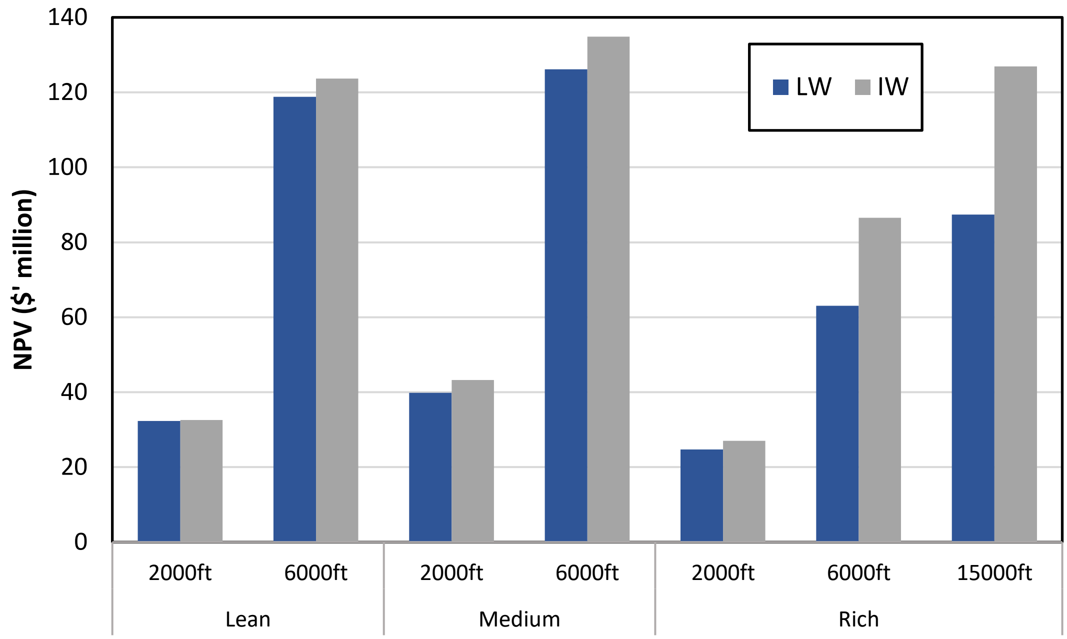


Figure 6-17. Recovery factors of untreated gas condensate reservoirs



.0

Figure 6-18. NPV from of 20-year production of untreated and treated reservoirs

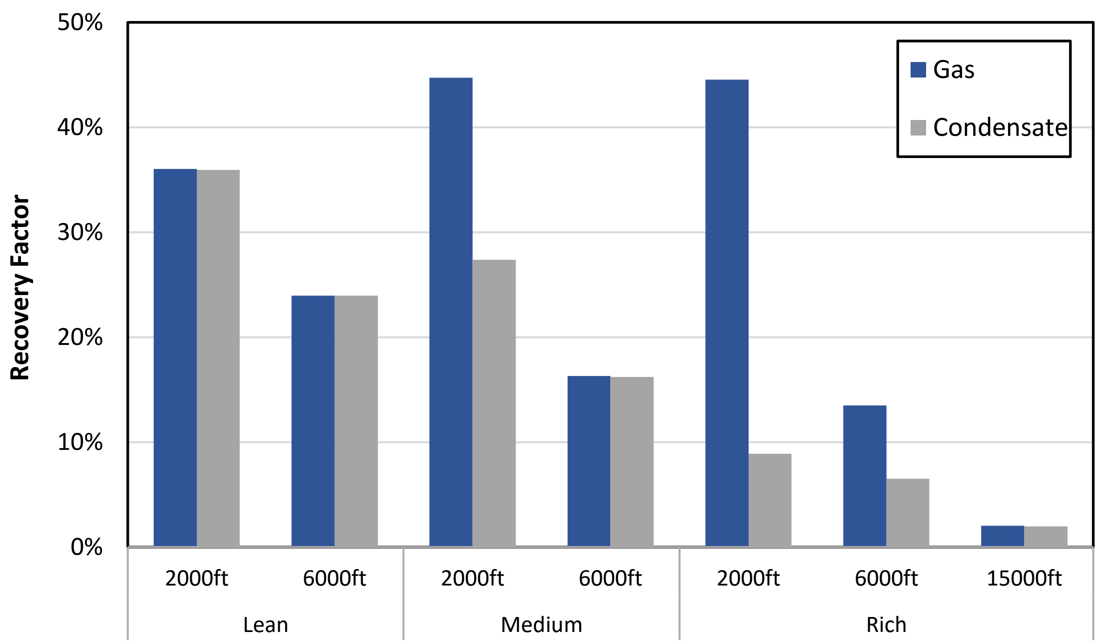


Figure 6-19. Recovery factors of intermediate wetting treated reservoirs

Table 6-2 Results for production and treatment of lean gas reservoir

R (ft.)	Wet type	Max. Q (MMScf/D)	BHP (Psia)	NPV (Million)	Cum. Gas (MMMSCF)	Cum. oil (MMSTB)	OGIP (MMMSCF)	OOIP (MMSTB)	G-RF	O-RF
2000	LW	10.00	2500	$ 32.31	12.50	0.49	34.70	1.36	35.98%	35.90%
6000	LW	11.50	2250	$ 118.78	69.40	2.71	312.70	12.20	22.20%	22.20%
15000	LW	10.50	2160	$ 119.20	76.70	3.00	1,954.60	76.38	3.92%	3.92%
2000	IW	15.00	2500	$ 32.54	12.52	0.49	34.70	1.36	36.04%	35.93%
2000	GW	15.00	2500	$ 30.34	12.50	0.49	34.70	1.36	35.98%	35.91%
6000	IW	11.50	2250	$ 123.67	79.97	2.93	312.73	12.22	23.97%	23.97%
6000	GW	11.50	2250	$ 114.10	66.82	2.61	312.73	12.22	21.37%	21.37%

Table 6-3 Results for production and treatment of medium gas reservoir

R (ft.)	Wet type	Max. Q (MMScf/D)	BHP (Psia)	NPV (Million)	Cum. Gas (MMMSCF)	Cum. oil (MMSTB)	OGIP (MMMSCF)	OOIP (MMSTB)	G-RF	O-RF
2000	LW	8.42	2075	$ 39.81	13.45	0.84	31.29	3.01	42.97%	27.88%
6000	LW	7.50	1900	$ 126.15	40.87	3.93	281.59	27.05	14.51%	14.51%
15000	LW	7.20	1750	$ 141.44	52.60	5.05	1,759.93	169.07	2.99%	2.99%
2000	IW	8.42	1750	$ 43.25	14.00	0.82	31.29	3.01	44.73%	27.37%
2000	GW	8.42	1750	$ 41.77	13.88	0.83	31.29	3.01	44.36%	27.56%
6000	IW	7.50	1900	$ 134.85	45.90	4.38	281.59	27.05	16.30%	16.21%
6000	GW	7.50	1900	$ 133.09	45.11	4.32	281.59	27.05	16.02%	15.97%

Table 6-4 Results for production and treatment of rich gas reservoir

R (ft.)	Wet type	Max. Q (MMScf/D)	BHP (Psia)	NPV (Million)	Cum. Gas (MMMSCF)	Cum. oil (MMSTB)	OGIP (MMMSCF)	OOIP (MMSTB)	G-RF	O-RF
2000	LW	8.00	2075	$ 24.68	12.76	0.41	28.68	4.25	44.50%	9.72%
6000	LW	7.30	1900	$ 63.08	21.21	2.04	258.11	38.23	8.22%	5.34%
15000	LW	6.75	1750	$ 87.40	23.12	3.42	1,613.21	238.93	1.43%	1.43%
2000	IW	8.00	1750	$ 27.04	12.77	0.38	28.68	4.25	44.53%	8.89%
2000	GW	8.00	1750	$ 25.78	12.77	0.39	28.68	4.25	44.53%	9.16%
6000	IW	7.30	1900	$ 86.54	34.86	2.49	258.11	38.23	13.51%	6.52%
6000	GW	7.30	1900	$ 84.00	32.76	2.48	258.11	38.23	12.69%	6.49%
15000	IW	6.75	1901	$ 126.88	32.65	4.72	1,613.21	238.93	2.02%	1.98%

The optimal wetting condition that has been established to optimized well deliverability would be utilized in the spacing analysis. In addition, the NPV from the 20-year gas and condensate production would assess the optimal spacing option. From our estimate, maximum of five 2000-ft radial reservoir would drain from a 6000-ft radial reservoir, while a maximum of four 6000-ft reservoirs would drain from a 15000-ft reservoir with little to no interference at the boundary.

Table 6-5 Spacing option for lean gas reservoir

	2000 ft.	6000 ft.	15000 ft.
2000 ft.	(x1)	(x5)	(x20)
	$ 32,500,000	$ 162,700,000	$ 650,900,000
6000 ft.		(x1)	(x4)
		$ 123,700,000	$ 494,700,000
15000 ft.			(x1)
			$ 119,200,000

Table 6-6 Spacing option for medium gas reservoir

	2000 ft.	6000 ft.	15000 ft.
2000 ft.	(x1)	(x5)	(x20)
	$ 43,300,000	$ 216,300,000	$ 865,000,000
6000 ft.		(x1)	(x4)
		$ 134,900,000	$ 539,400,000
15000 ft.			(x1)
			$ 141,400,000

Table 6-7 Spacing option for rich gas reservoir

	2000 ft.	6000 ft.	15000 ft.
2000 ft.	(x1)	(x5)	(x20)
	$ 27,000,000	$ 135,200,000	$ 540,800,000
6000 ft.		(x1)	(x4)
		$ 86,500,000	$ 346,100,000
15000 ft.			(x1)
			$ 126,900,000

Tables 6-5, 6-6, and **6-7** show that if five well were to be drilled in a 6000-ft radius reservoir to drain from an average 2000-ft radius, the overall deliverability would outperform that of a single well in the same reservoir. The approach would increase well deliverability by over 30% for the lean gas reservoir, by over 60% for medium gas reservoir and improve deliverability in the rich gas reservoir by about 55%. Likewise, if four wells were drilled in a 15000-ft reservoir to drain from an average of 6000-ft radius, the strategies could improve the overall well deliverability by a factor of 3 on average.

Chapter 7: Conclusions

This study presents a three-part analysis to investigate wettability alteration in gas condensate reservoir system. Initially, we expanded on past studies (Zogbhi et al. 2010, Weiss. 2017, and Ajagbe et al. 2018) to create a more robust simulation model to investigate the stimulation method. We then proceed to subject our observations to statistical analysis in an attempt to understand the level of influence of various parameters in our model on the effectiveness of wettability treatment and to draw statistically plausible conclusions. Finally, we proceeded to investigate the use of well spacing in conjunction with wettability alteration treatment to optimize production from gas condensate reservoir. Our key observations are summarized in **section 5.1** and we hinted on a possible direction for next studies on utilization of wettability alteration to enhance well deliverability in gas condensate reservoir system in **section 5.2**.

7.1 KEY OBSERVATIONS.

- A state of intermediate wetting condition is most favorable to ensure both gas and condensate mobility and hence, results in optimal post-treatment well deliverability.
- Wettability alteration treatment is more effective in a low permeability reservoir relative to a reservoir with large permeability value. The impact of condensate blocking commonly experienced in gas condensate reservoir is more severe in low permeability reservoir gas, hence the post-treatment increase in gas and condensate production is always substantial to offset the cost of treatment.
- This study also established that for reservoir gas with low condensate yield would require smaller treatment radius relative to reservoir gas with high condensate yield. In

this study, a 5-ft treatment radius was the better treatment radius option for lean and medium fluid, while a 15-ft treatment radius works better for a rich fluid.

- Also, reservoir gas with low condensate yield would generally be a poor treatment candidate. The condensate accumulation in the near-wellbore region for such a reservoir is minimal and the post-treatment increased in gas and condensate rate is often not significant enough to offset the treatment cost.
- In general, wettability alteration treatment is very effective when the reservoir contains a medium fluid whose condensate yield is between 75 – 115 bbl/MMScf.
- Wetting type, treatment radius, reservoir size, and permeability all have a significant influence on the performance of wettability alteration treatment in gas reservoirs. The interaction of these factors could also be influential to the post-treatment performance of the reservoir depending on the condensate yield of reservoir gas.
- The use of increased gas rate or cumulative gas production in past simulation studies fails to penalize cases where wettability treatment has zero or unsubstantial impact on well deliverability. In this study, we introduce a new metric to evaluate post-treatment performance of wettability alteration that features the cost of treatment, amongst other expenses considered. As a result, we have so many cases where gas-wetting treatments result in negative post-treatment performance.
- Smaller drainage area reservoirs would generally have higher recovery factors than large drainage gas condensate reservoirs. Hence, a combination of well spacing and wettability alteration is a good strategy to optimize the deliverability from gas condensate reservoirs.

- In conclusion, a gas condensate reservoir, with small drainage area, low permeability and containing medium fluid whose wettability as been altered to intermediate wetting condition would give a superior post-treatment well enhancement.

7.2 SUGGESTIONS FOR FUTURE STUDY.

This study used a very simple idealistic reservoir, a more robust study would involve modeling the reservoir after a real reservoir featuring every form of heterogeneity in the reservoir properties.

An introduction of water saturation to the simulation model would help to understand how the post-treatment gas and condensate mobility changes in the presence of a third phase. In addition, cost of water treatment should be included in the analysis to investigate the practicality of wettability alteration treatment in as condensate reservoir.

A study of the mechanism of the absorption of the treatment chemical solution is also necessary. The treatment performance will be different if the wettability alteration polymer solution is absorbed evenly within the treatment zone compare to when there is a differential absorption thereby creating zones with different extent of treatment. A simulation model considering a differential absorption with of treatment chemical solution should also be investigated to evaluate treatment effectiveness in such situation.

A practical angle to the well spacing analysis introduced in this study would be to consider the maximum possible tubing size that can produce the gas condensate reservoir for each considered drainage radius from vertical lift performance. The equilibrium rate and bottom hole pressure from the nodal analysis should be used as input of the production simulation in CMG.

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Nomenclature

h	Reservoir thickness, ft.
k	Permeability, md
k_{rg}	Relative permeability to gas
k_{ro}	Relative permeability to oil
P_c	Capillary pressure, dynes
p_g	Gas phase pressure, dynes
p_o	Oil phase pressure, dynes
p_{wf}	Bottomhole flowing pressure, psia
$\bar{p}$	Average reservoir pressure, psia
r_p	pore size, cm
r_e	Radius of reservoir, ft.
r_w	Radius of the wellbore, ft.
S_g	Gas saturation
S_o	Oil saturation
s	skin factor
q	Flow rate, cm^3/s or Scf/D or bbl/D
θ	Contact angle, radians,
σ	Condensate-gas Interfacial tension, $dynes/cm^2$
μ	Viscosity, cp
Z	Gas compressibility factor, $Psia^{-1}$

Abbreviations

bbl	Reservoir barrel
BHP	Bottom hole pressure
CCE	Constant composition expansion
CMG	Computer Modelling Group
Cum. Gas	Cumulative gas produced
Cum. Oil	Cumulative Oil produced
GOR	Gas-oil ratio
G-RF	Gas recovery factor
Max. Q	Maximum gas flow rate
MMcf	Million cubic feet
MMSTB	Million stock tank barrels
Mcf	Thousand cubic feet
MSTB	Thousand stock tank barrels
NPV	Net present value
OGIP	Original gas in place
OOIP	Original oil in place
O-RF	Oil recovery factor
Scf	Standard cubic feet
STB	Stock-tank barrel
Wet. Type	Reservoir wettability

Appendix

Additional plots for the simulation of wettability alteration treatment in chapter 4

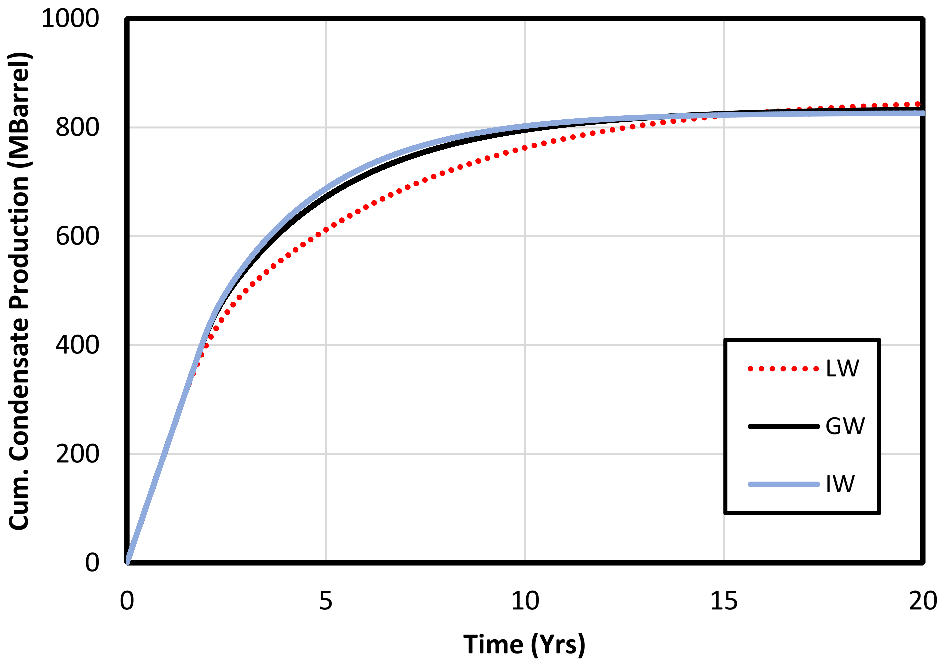

Figure 8-1. Cumulative condensate production from a 2000 ft., 10 md. reservoir containing medium fluid

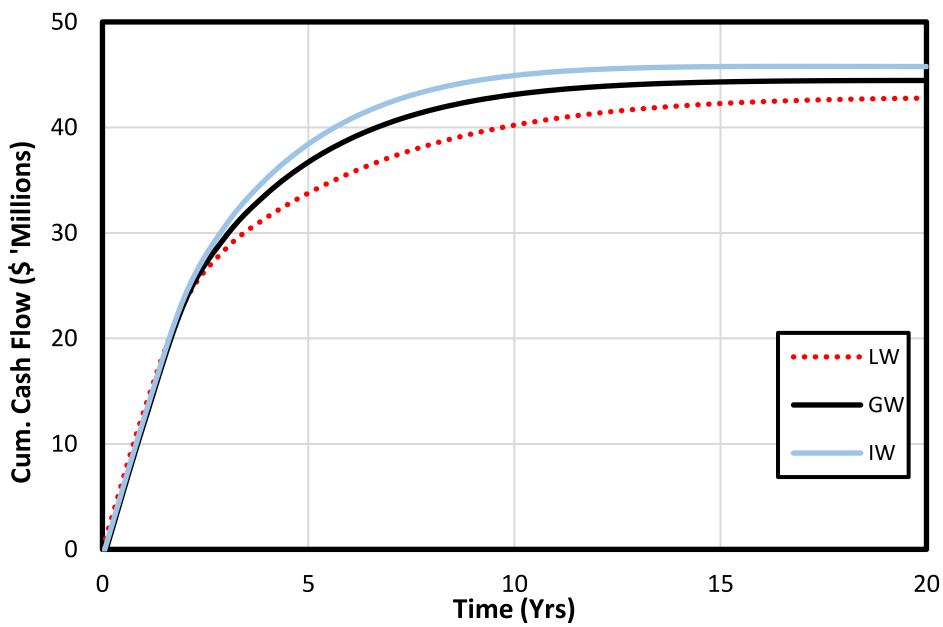

Figure 8-1. Cumulative cash flow from a 2000 ft., 10 md. reservoir containing medium fluid

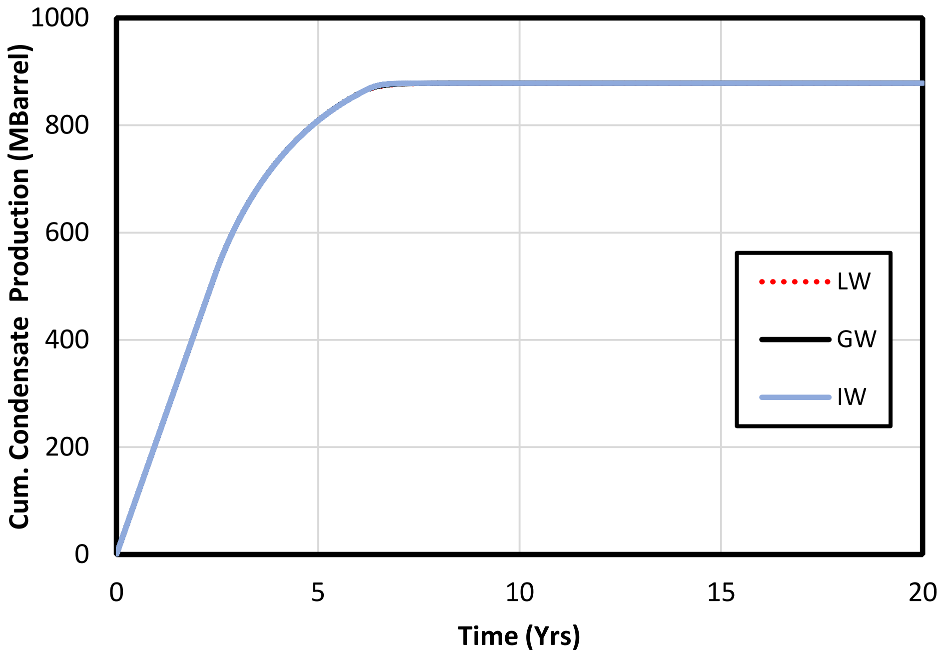

Figure 8-3. Cumulative condensate production from a 2000 ft., 100 md. reservoir containing medium fluid

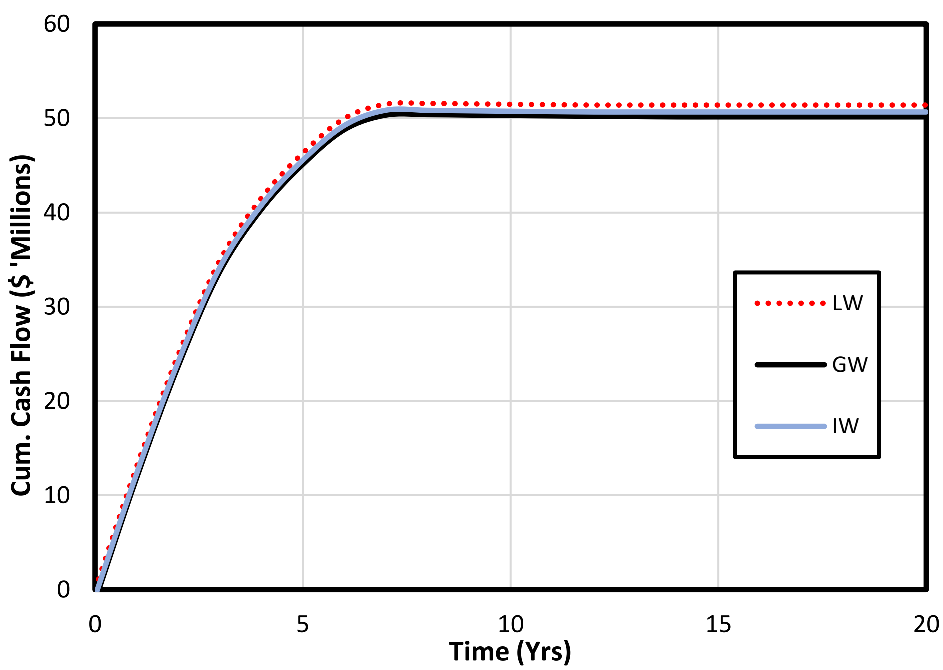

Figure 8-4. Cumulative cash flow from a 2000 ft., 100 md. reservoir containing medium fluid

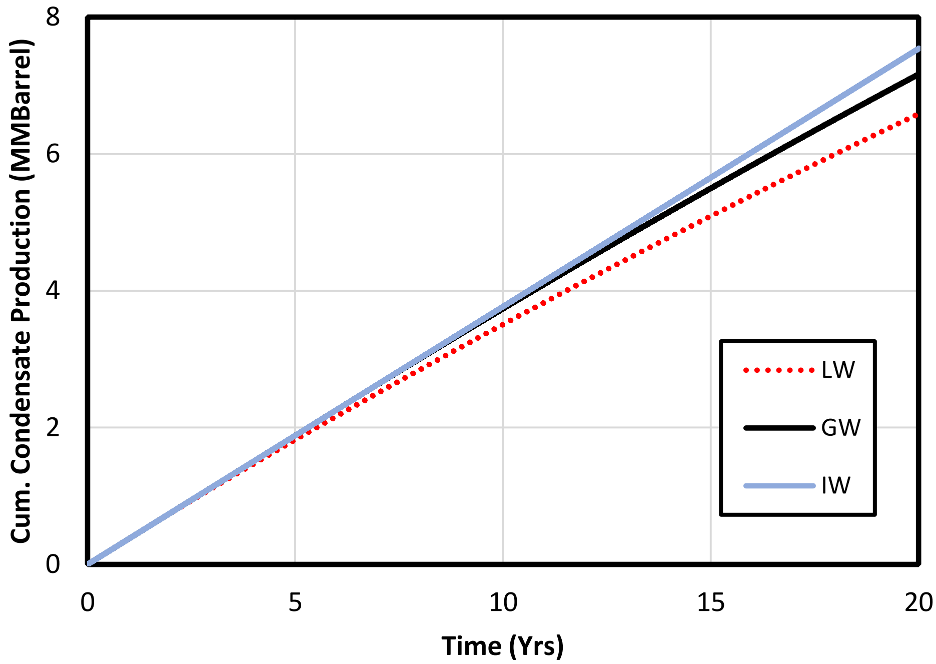

Figure 8-5. Cumulative condensate production from a 15000 ft., 10 md. reservoir containing medium fluid

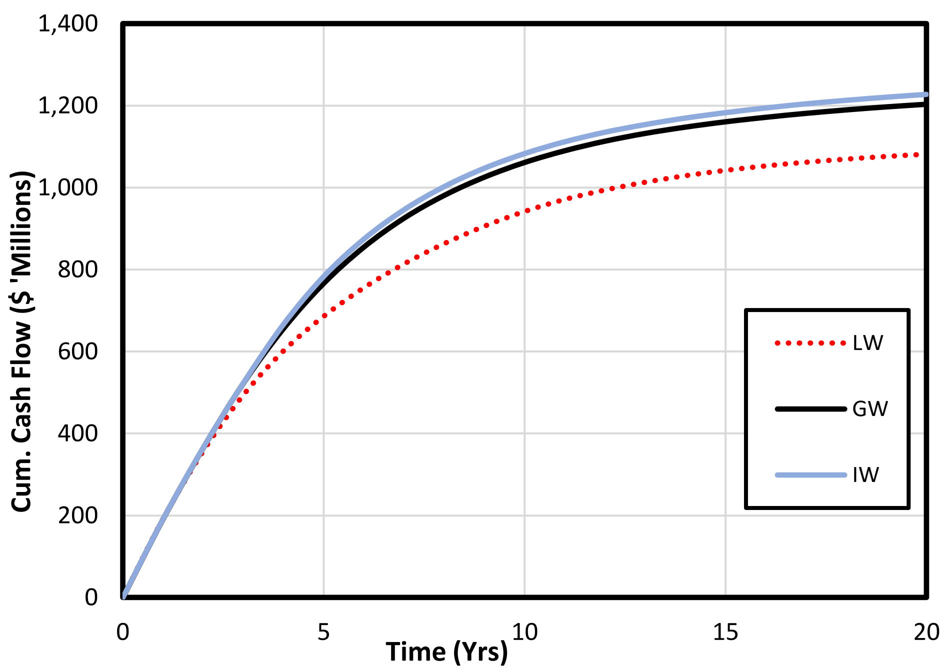

Figure 8-6. Cumulative cash flow from a 15000 ft., 10 md. reservoir containing medium fluid

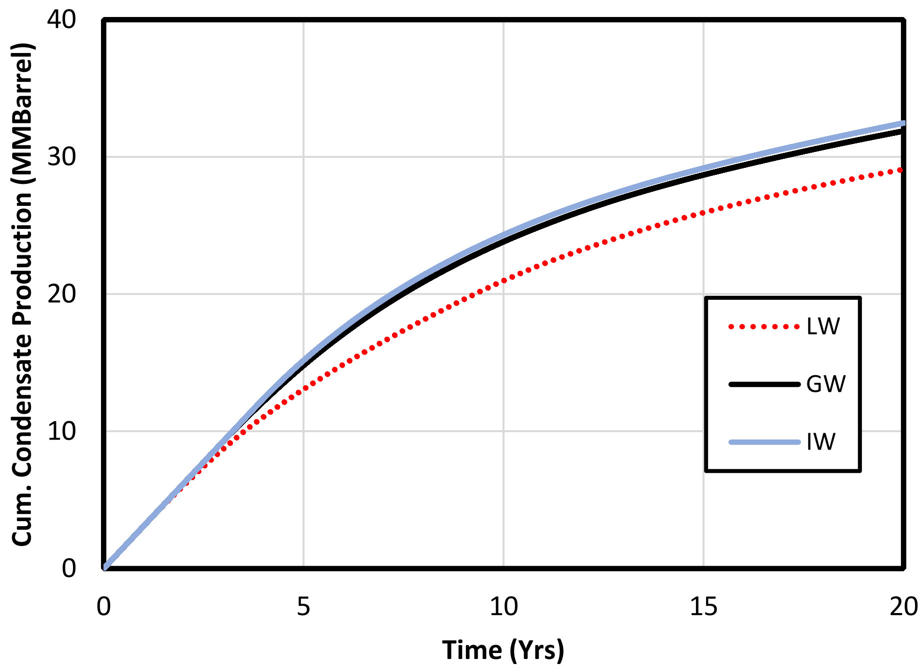

Figure 8-7. Cumulative condensate production from a 15000 ft., 100 md. reservoir containing medium fluid

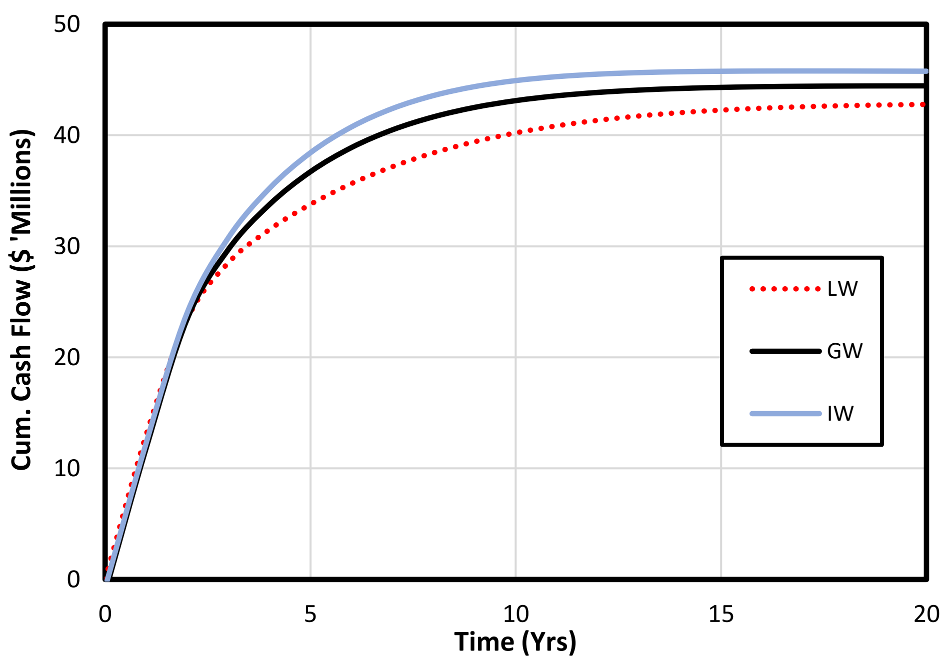

Figure 8-8. Cumulative cash flow from a 15000 ft., 100 md. reservoir containing medium fluid\

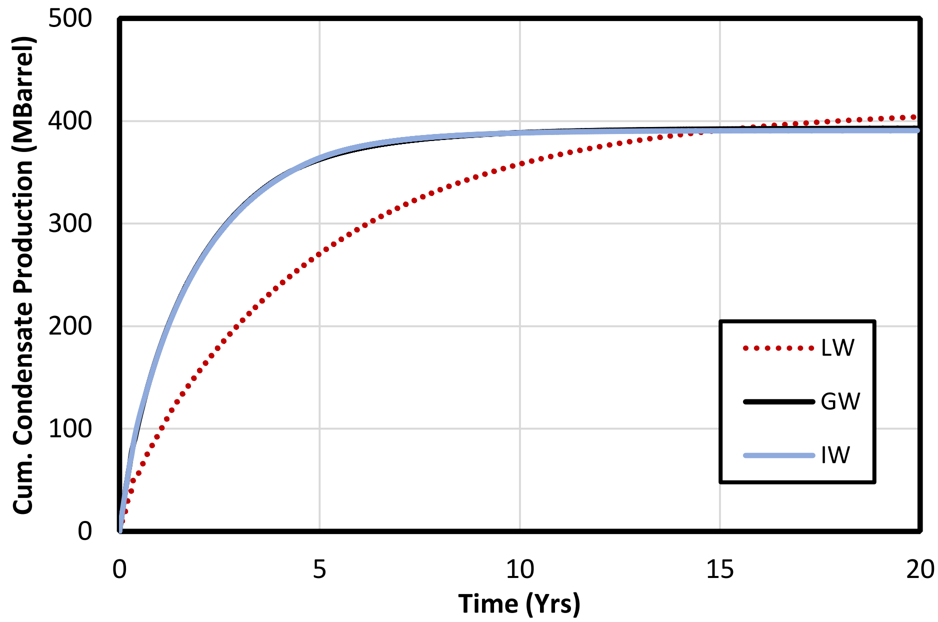

Figure 8-9. Cumulative condensate production from a 2000 ft., 10 md. reservoir containing rich fluid

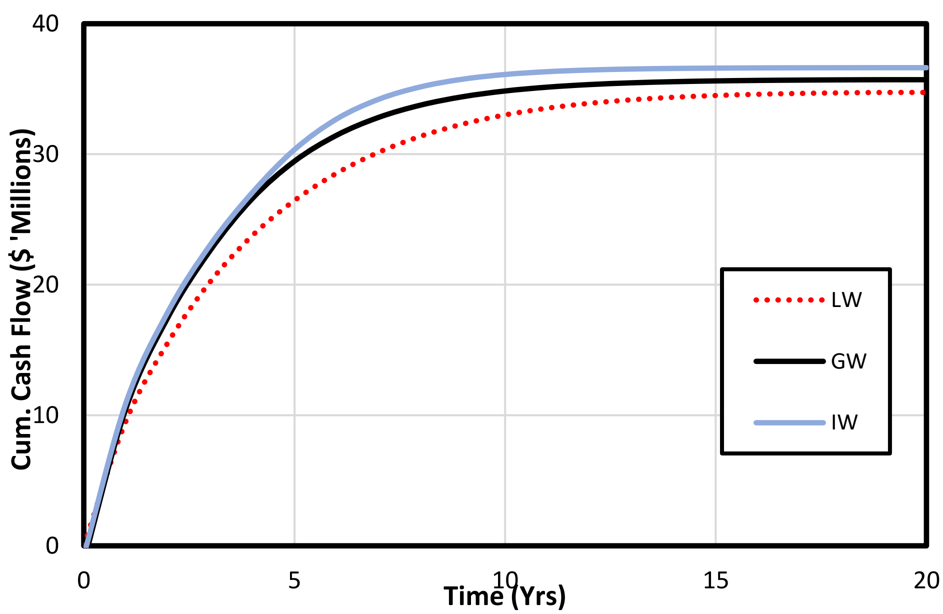

Figure 8-10. Cumulative cash flow from a 2000 ft., 10 md. reservoir containing rich fluid

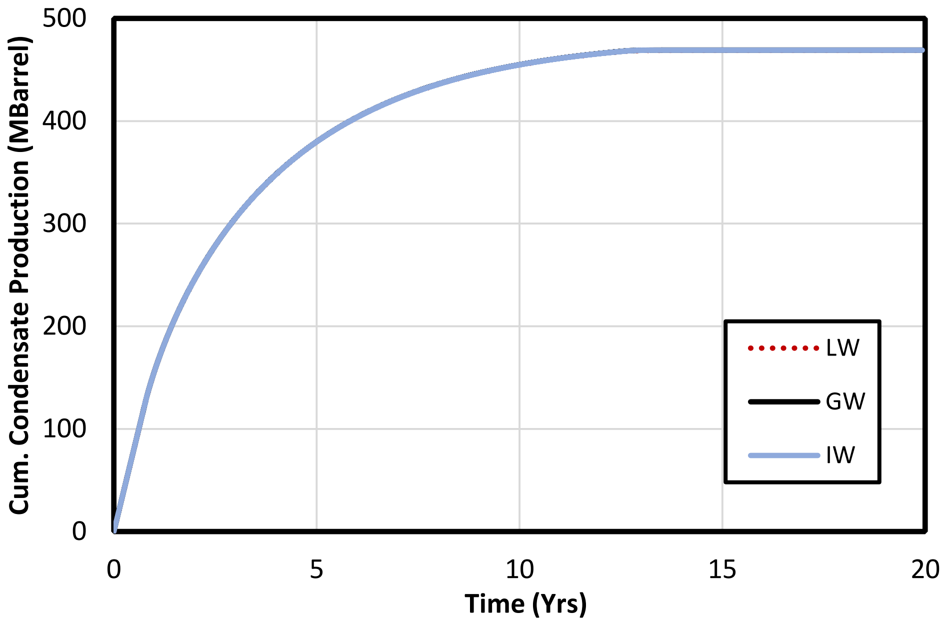

Figure 8-11. Cumulative condensate production from a 2000 ft., 100 md. reservoir containing rich fluid

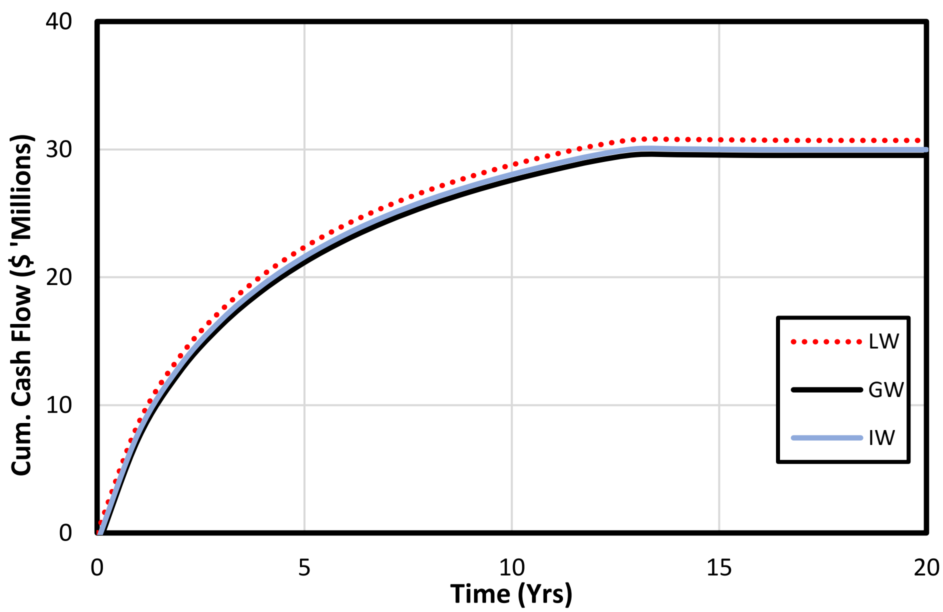

Figure 8-12. Cumulative cash flow from a 2000 ft., 100 md. reservoir containing rich fluid

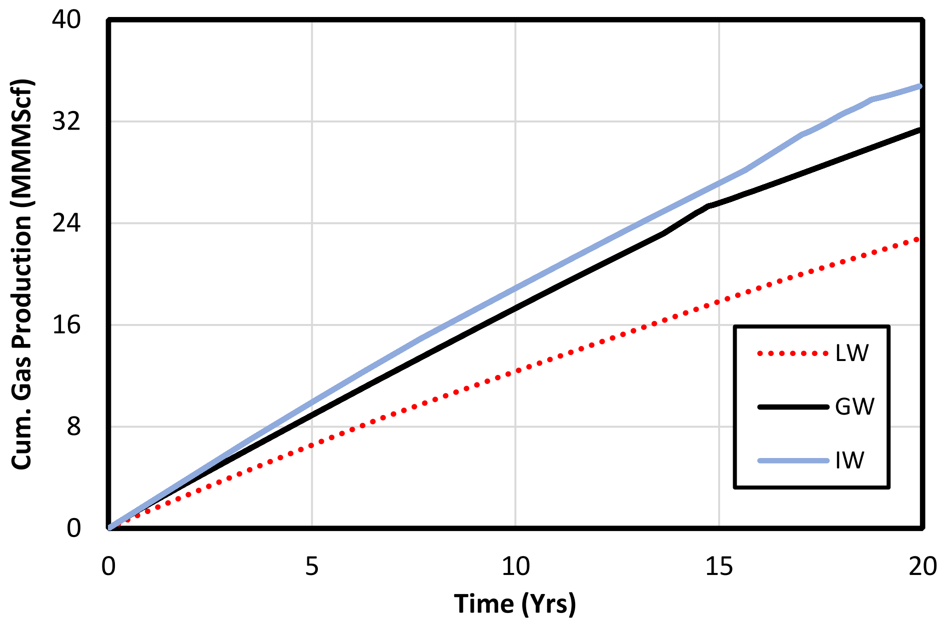

Figure 8-13. Cumulative condensate production from a 15000 ft., 10 md. reservoir containing rich fluid

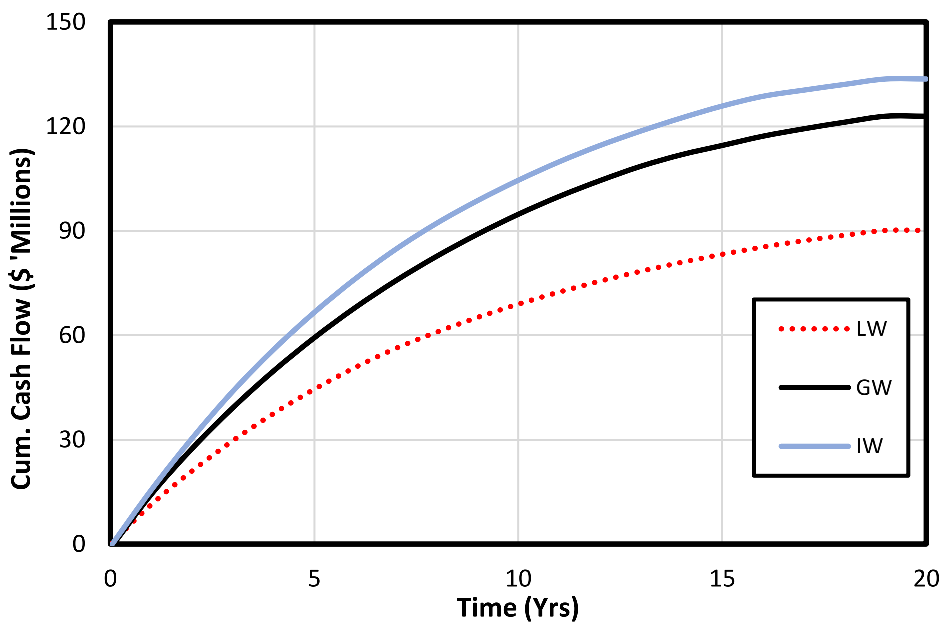

Figure 8-14. Cumulative cash flow from a 15000 ft., 10 md. reservoir containing rich fluid

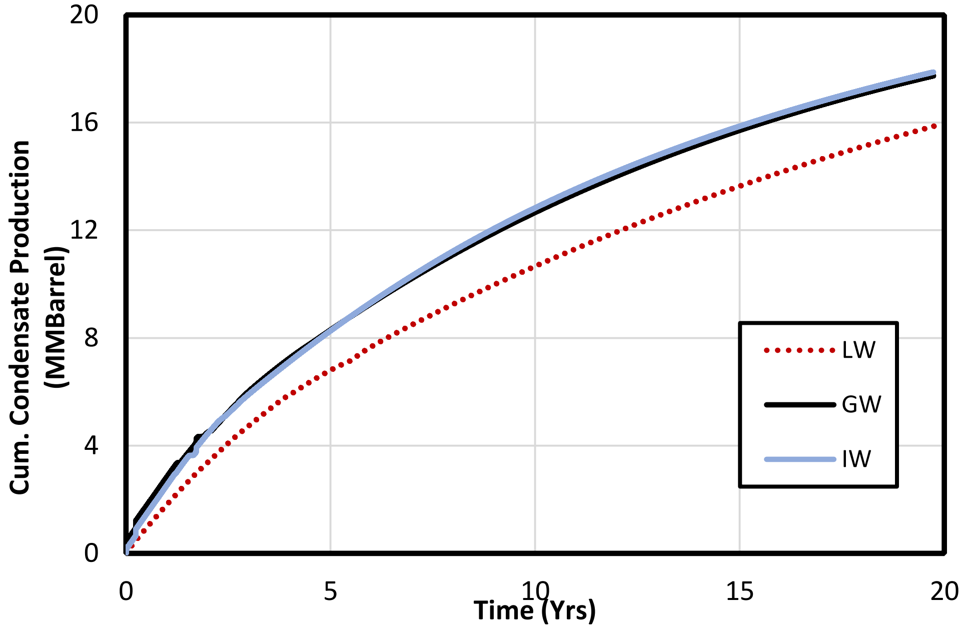

Figure 8-15. Cumulative condensate production from a 15000 ft., 100 md. reservoir containing rich fluid

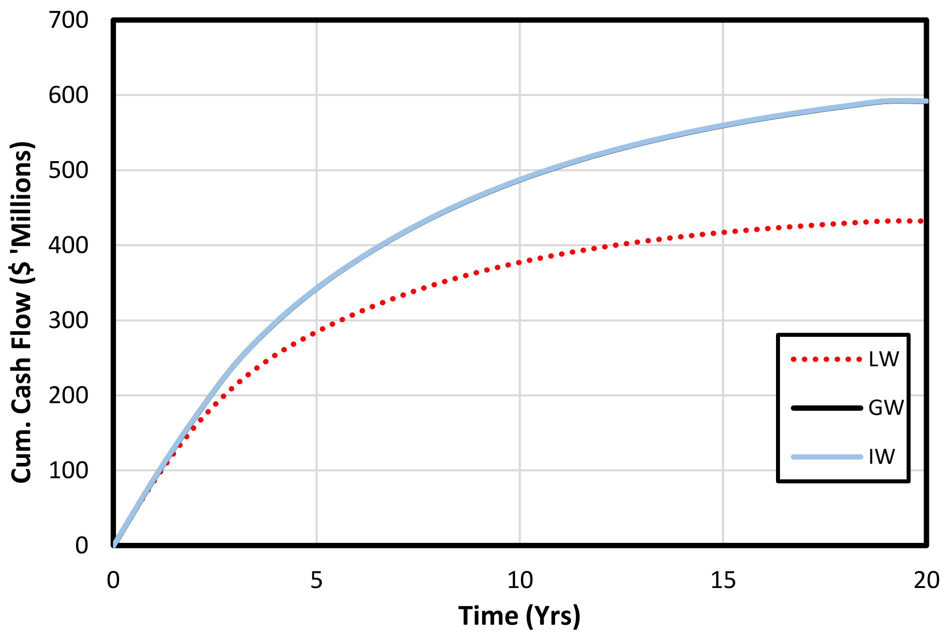

Figure 8-16. Cumulative cash flow from a 15000 ft., 100 md. reservoir containing rich fluid

Analysis of performance of wettability alteration treatment in chapter 4

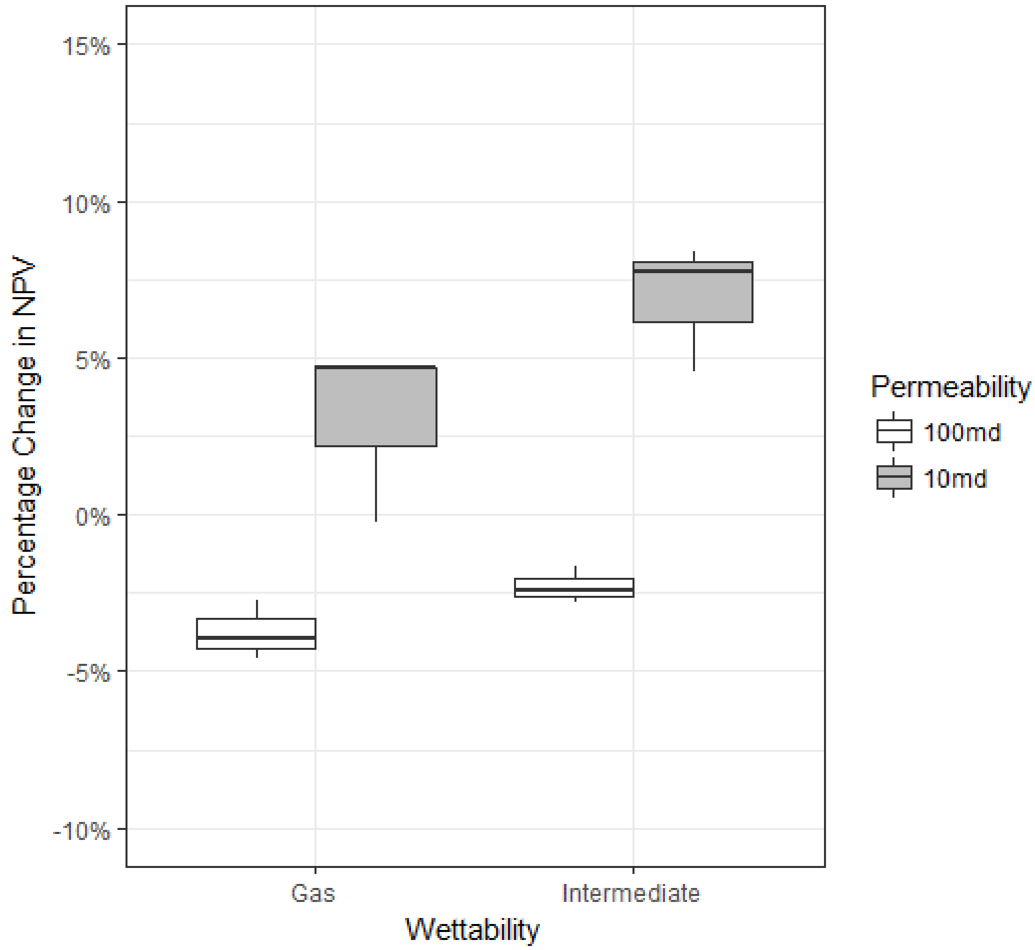

Figure 8-17. Evaluation of wettability alteration by permeability for 2000-ft reservoir

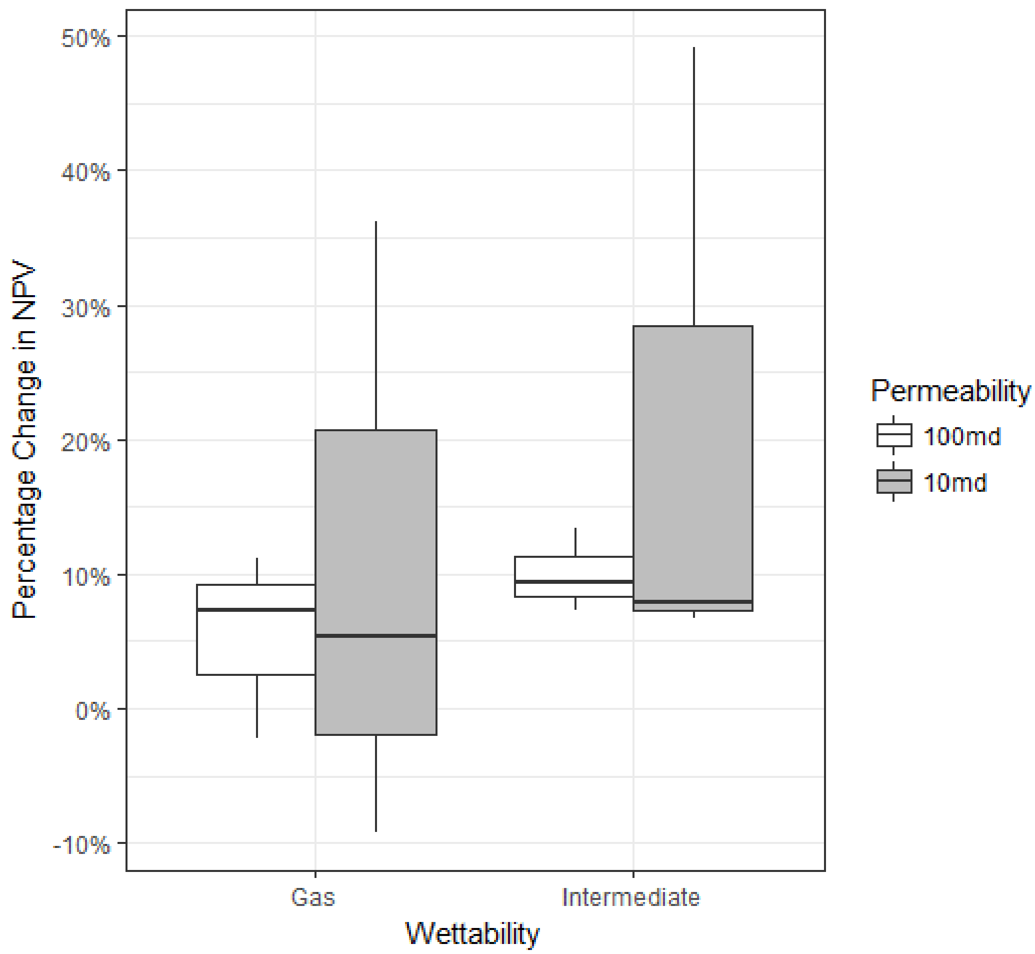

Figure 8-18. Evaluation of wettability alteration by permeability for 15000-ft reservoir

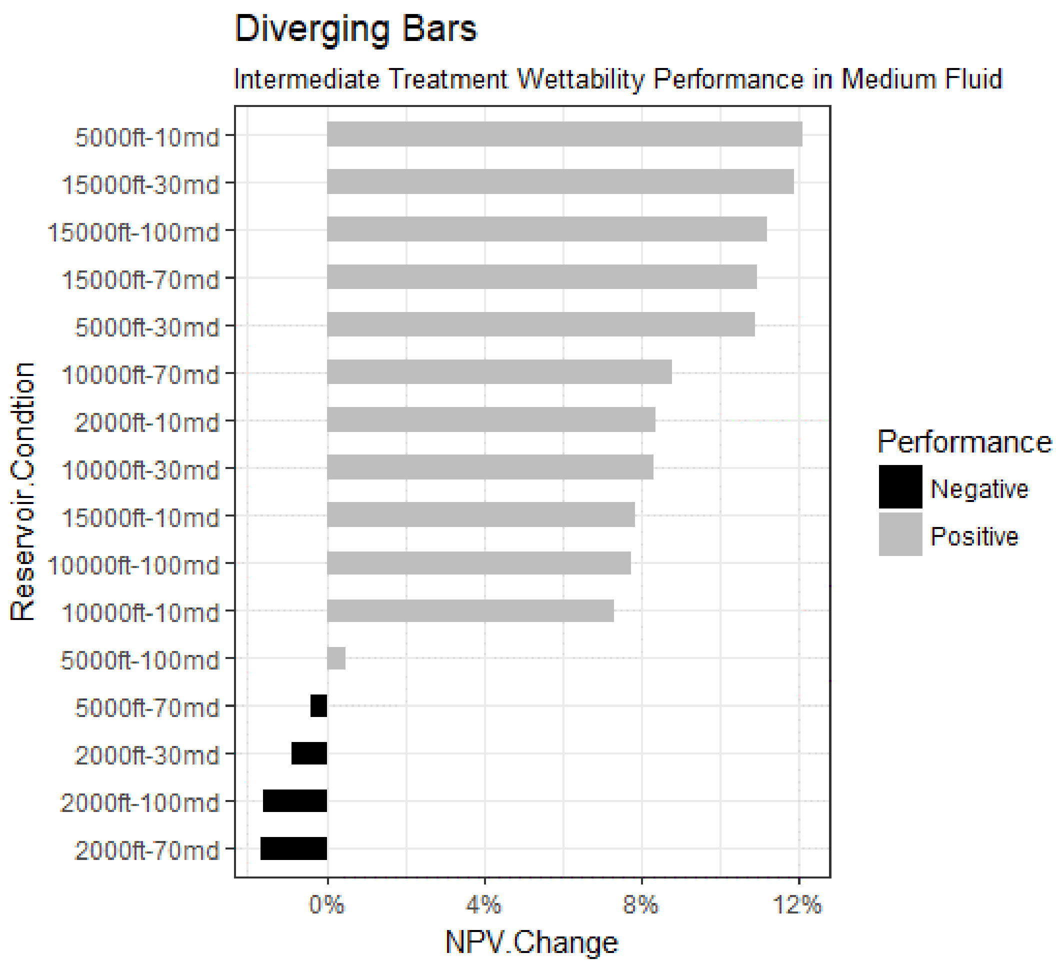

Figure 8-19. Evaluation of wettability alteration by permeability and reservoir

Pre and post treatment condensate production for analysis in chapter 6

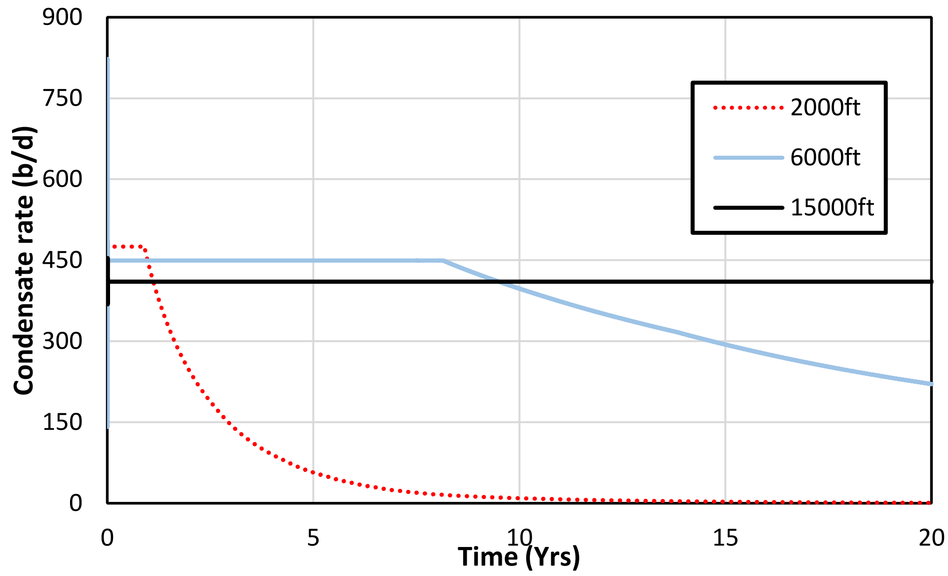

Figure 8-20. condensate rate from lean gas reservoirs at default wetting condition

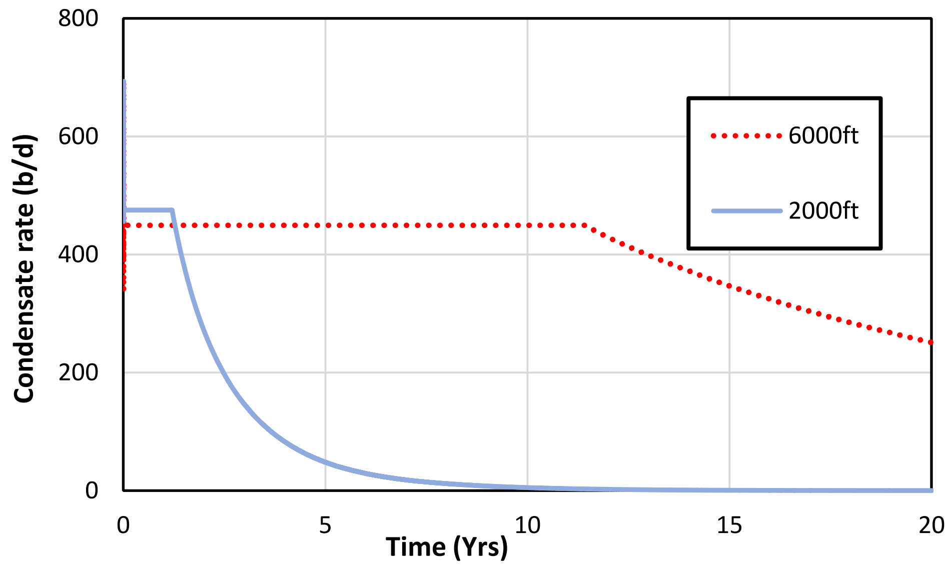

Figure 8-21. condensate rate from intermediate wetting lean gas reservoir

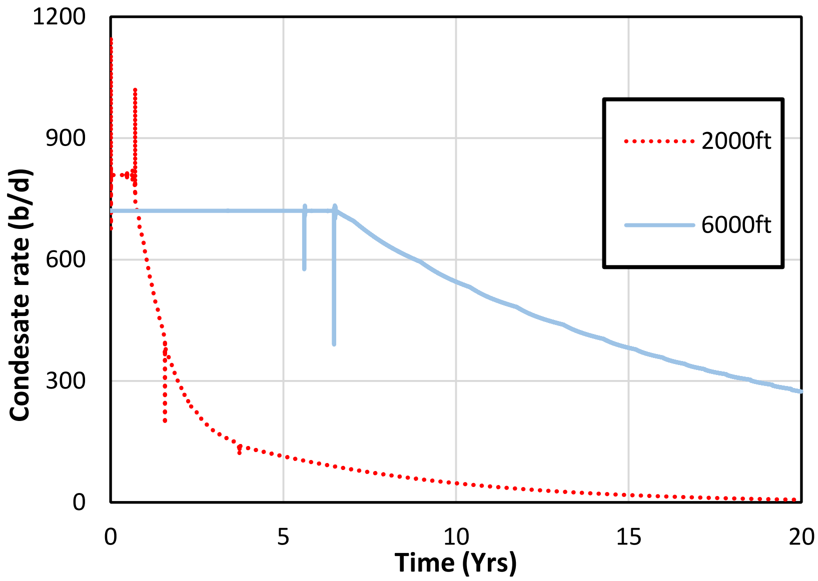

Figure 8-22. condensate rate from medium gas reservoir at default wetting state

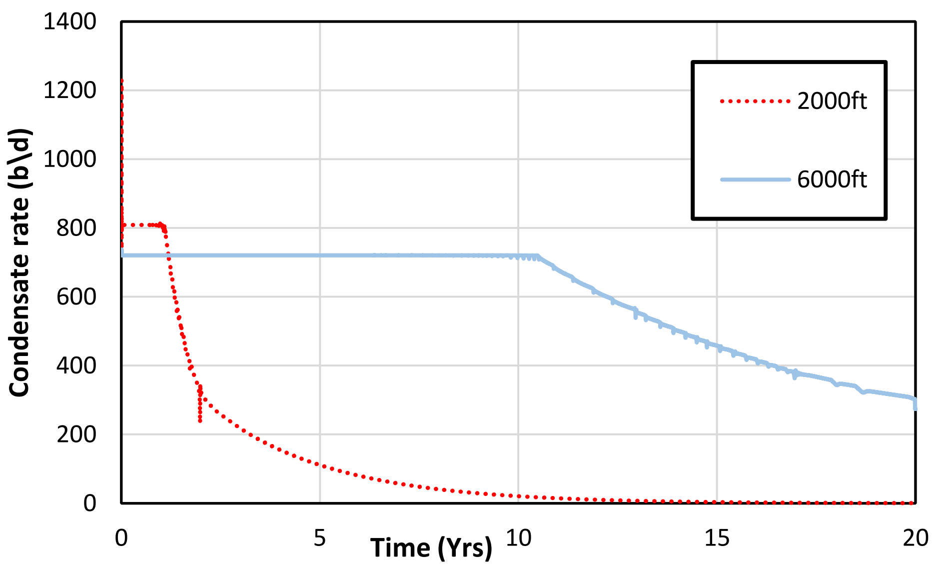

Figure 8-23. condensate rate from intermediate wetting medium gas reservoir

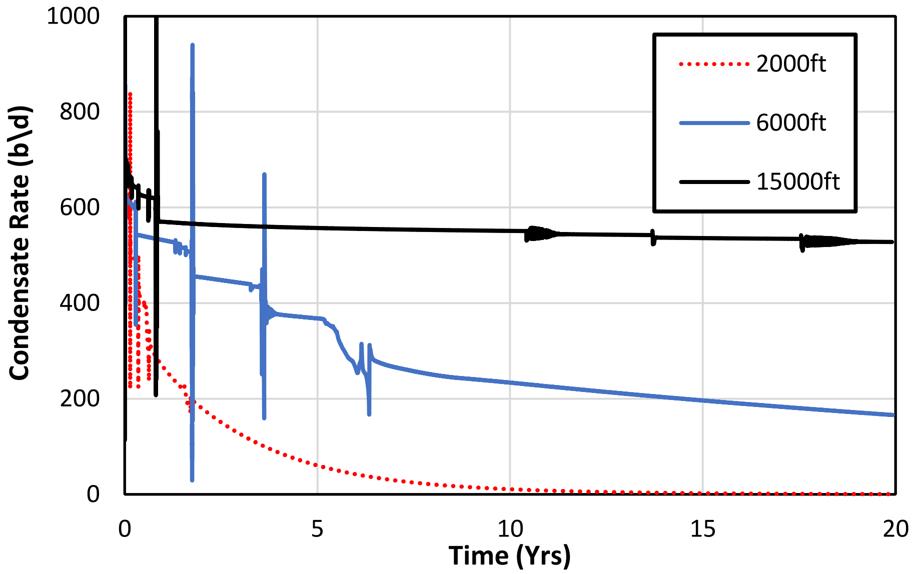

Figure 8-24. condensate rate from rich gas reservoir at default wetting condition

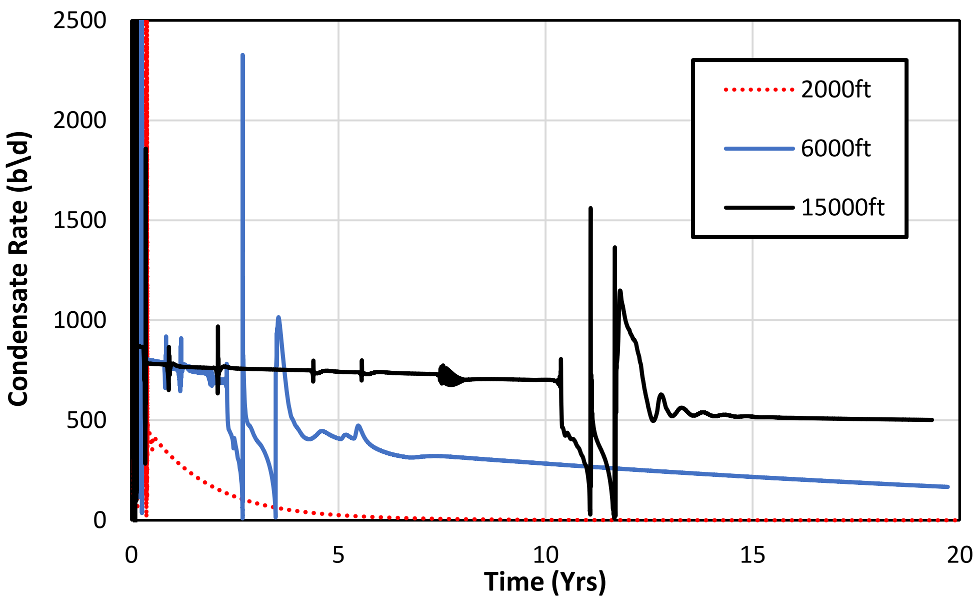

Figure 8-25. condensate rate from intermediate wetting rich gas reservoir

Contrast and main effect estimated from 2k factorial results in chapter 5

Table 8-1. Calculation of contrast and main effect for Lean fluid

	A	B	C	D	AB	AC	AD	BC	BD	CD	ABC	ABD	BCD	ABCD
contrast	-1.315	0.050	-0.178	0.175	0.353	-0.050	-0.952	0.027	0.631	0.137	0.007	0.119	0.004	0.000
Main effect	-0.082	0.003	-0.011	0.011	0.022	-0.003	-0.060	0.002	0.039	0.009	0.000	0.007	0.000	0.000

Table 8-2. Calculation of contrast and main effect for Medium fluid

	A	B	C	D	AB	AC	AD	BC	BD	CD	ABC	ABD	BCD	ABCD
contrast	-0.360	-0.985	-0.445	1.358	-0.293	0.093	-0.078	0.559	-0.005	-0.377	0.309	-0.437	0.667	0.314
Main effect	-0.022	-0.062	-0.028	0.085	-0.018	0.006	-0.005	0.035	0.000	-0.024	0.019	-0.027	0.042	0.020

Table 8-3. Calculation of contrast and main effect for Rich fluid.

	A	B	C	D	AB	AC	AD	BC	BD	CD	ABC	ABD	BCD	ABCD
contrast	-0.527	-1.241	0.514	4.217	0.106	-0.07	-0.17	-0.47	-0.873	0.908	0.006	0.193	-0.49	-4E-03
Main effect	-0.033	-0.078	0.032	0.264	0.007	-4E-03	-0.011	-0.03	-0.055	0.057	4E-04	0.012	-0.03	-3E-04

Additional information about fluid types and relative permeability models in chapter 3

Table 8-4 Compositional information and properties of lean fluid.

Component	**Lean Composition, wt.%**	**Pc, atm**	**Tc, K**	**Acentric Factor**	**Molecular Weight, g/mol**	**Viscosity, cp**	**Specific Gravity**	**Parachor**
N2	1.19	33.5	126.2	0.04	28.013	0.09	0.809	41
CO2	1.58	72.8	304.2	0.225	44.01	0.094	0.818	78
C1	75.82	45.4	190.6	0.008	16.043	0.099	0.3	77
C2	4.85	48.2	305.4	0.098	30.07	0.148	0.356	108
C3	3.57	41.9	369.8	0.152	44.097	0.203	0.507	150.3
i-C4	0.96	36	408.1	0.176	58.124	0.263	0.563	181.5
nC4	0.93	37.5	425.2	0.193	58.124	0.255	0.584	189.9
i-C5	1.01	33.4	460.4	0.227	72.151	0.306	0.625	225
nC5	2.01	33.3	469.6	0.251	72.151	0.304	0.631	231.5
C6	3.53	32.5	507.5	0.275	86	0.344	0.69	250.1
C7+	4.54	31.7	554	0.424	108	0.49	0.736	433.845

Table 8-5 Compositional information and properties of Medium fluid.

Component	Rich Composition, wt.%	Pc, atm	Tc, K	Acentric Factor	Molecular Weight, g/mol	Viscosity, cp	Specific Gravity	Parachor
N2	1.01	33.5	126.2	0.04	28.013	0.09	0.809	41
CO2	1.01	72.8	304.2	0.225	44.01	0.094	0.818	78
C1	65.58	45.4	190.6	0.008	16.043	0.099	0.3	77
C2	8.9	48.2	305.4	0.098	30.07	0.148	0.356	108
C3	6.78	41.9	369.8	0.152	44.097	0.203	0.507	150.3
i-C4	0	36	408.1	0.176	58.124	0.263	0.563	181.5
nC4	3.28	37.5	425.2	0.193	58.124	0.255	0.584	189.9
i-C5	0	33.4	460.4	0.227	72.151	0.306	0.625	225
nC5	2.02	33.3	469.6	0.251	72.151	0.304	0.631	231.5
C6	5.89	32.5	507.5	0.275	86	0.344	0.69	250.1
C7+	5.52	18.1	736.3	0.585	201	0.793	0.884	548.945

Table 8-6 Compositional information and properties of Rich fluid.

Component	Medium Composition, wt.%	Pc, atm	Tc, K	Acentric Factor	Molecular Weight, g/mol	Viscosity, cp	Specific Gravity	Parachor
C1+N2	67.93	45.08	188.7	0.0089	16.385	0.099	0.26214	40.9
C2+CO2	9.9	50.36	305.3	0.1135	31.774	0.141	0.44809	89
C3	5.91	41.9	369.8	0.152	44.097	0.203	0.507	150.3
C4+C5	7.86	35.61	433.9	0.2029	62.925	0.274	0.59121	183.1
C6	1.81	32.46	507.5	0.2637	86	0.344	0.68013	250.1
C7-C12	5.18	26.96	586.7	0.3346	119.02	0.47	0.75386	341.9
C13+	1.41	19.3	729.3	0.5972	217.12	0.749	0.8667	586.2

Table 8-7 Properties of C7+ fraction for lean and Rich, and C13+ for Medium fluid composition

Property	Lean Fluid	Medium Fluid	Rich Fluid
Acentric Factor	0.424	0.597	0.585
Molecular Weight, g/mol	108	217	201
Viscosity, cp	0.49	0.749	0.793
Specific Gravity	0.736	0.867	0.884
Parachor	433.845	586.2	548.945
Pc, atm	31.7	19.3	18.1
Tc, K	554	729.3	736.3

Table 8-8 Relative permeability data for the three fluid.

Liquid-Wetting			Gas-Wetting			Intermediate-Wetting		
So	**krg**	**kro**	**So**	**krg**	**kro**	**So**	**krg**	**kro**
0.5	0.3	0	0.1	0.2	0	0.3	0.5	0
0.516	0.2709	0	0.1159	0.188	0.0004	0.3161	0.4606	0.0004
0.532	0.2436	0	0.1317	0.1765	0.0015	0.3323	0.4232	0.0017
0.548	0.2179	0	0.1476	0.1654	0.0035	0.3484	0.3877	0.0037
0.564	0.194	0.0001	0.1634	0.1547	0.0062	0.3645	0.354	0.0067
0.58	0.1717	0.0002	0.1793	0.1445	0.0097	0.3806	0.3221	0.0104
0.596	0.1511	0.0005	0.1951	0.1347	0.0139	0.3968	0.292	0.015
0.612	0.132	0.0009	0.211	0.1252	0.0189	0.4129	0.2637	0.0204
0.628	0.1144	0.0016	0.2268	0.1162	0.0247	0.429	0.2371	0.0266
0.644	0.0983	0.0025	0.2427	0.1076	0.0313	0.4452	0.2121	0.0337
0.66	0.0837	0.0038	0.2585	0.0994	0.0387	0.4613	0.1888	0.0416
0.676	0.0704	0.0056	0.2744	0.0916	0.0468	0.4774	0.1672	0.0504
0.692	0.0585	0.008	0.2902	0.0842	0.0557	0.4935	0.147	0.0599
0.708	0.0479	0.011	0.3061	0.0771	0.0653	0.5097	0.1285	0.0703
0.724	0.0385	0.0148	0.322	0.0704	0.0758	0.5258	0.1113	0.0816
0.74	0.0304	0.0194	0.3378	0.064	0.087	0.5419	0.0957	0.0937
0.756	0.0233	0.0252	0.3537	0.0581	0.099	0.5581	0.0814	0.1066
0.772	0.0174	0.0321	0.3695	0.0524	0.1117	0.5742	0.0685	0.1203
0.788	0.0124	0.0403	0.3854	0.0471	0.1253	0.5903	0.0569	0.1349
0.804	0.0085	0.05	0.4012	0.0422	0.1396	0.6065	0.0466	0.1503
0.82	0.0054	0.0614	0.4171	0.0376	0.1547	0.6226	0.0375	0.1665
0.836	0.0031	0.0747	0.4329	0.0332	0.1705	0.6387	0.0296	0.1836
0.852	0.0015	0.09	0.4488	0.0292	0.1872	0.6548	0.0227	0.2015
0.868	0.0005	0.1075	0.4646	0.0255	0.2046	0.671	0.0169	0.2202
0.884	0.0001	0.1274	0.4805	0.0221	0.2227	0.6871	0.0121	0.2398
0.9	0	0.15	0.4963	0.019	0.2417	0.7032	0.0082	0.2601
			0.5122	0.0162	0.2614	0.7194	0.0052	0.2814
			0.528	0.0136	0.2819	0.7355	0.003	0.3034
			0.5439	0.0113	0.3032	0.7516	0.0015	0.3263
			0.5598	0.0093	0.3252	0.7677	0.0005	0.3501
			0.5756	0.0075	0.348	0.7839	0.0001	0.3746
			0.5915	0.0059	0.3716	0.8	0	0.4
			0.6073	0.0045	0.396			
			0.6232	0.0034	0.4211			
			0.639	0.0024	0.447			
			0.6549	0.0016	0.4737			
			0.6707	0.001	0.5011			
			0.6866	0.0006	0.5294			
			0.7024	0.0003	0.5584			
			0.7183	0.0001	0.5881			
			0.7341	0	0.6187			
			0.75	0	0.65			